A Techno-Economic Analysis of Decentralized Electrolytic Hydrogen Production for Fuel Cell Vehicles

by

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B.A.Sc., Université Laval, 1996

A Thesis Submitted in Partial Fulfillment of the
Requirements for the Degree of

MASTER OF APPLIED SCIENCE

in the Department of Mechanical Engineering

University of Victoria

Abstract

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Hydrogen from decentralized water electrolysis is one of the main fuelling options considered for future fuel cell vehicles. In this thesis, a model is developed to determine the key technical and economic parameters influencing the competitive position of decentralized electrolytic hydrogen. This model, which incorporates the capital and energy costs of water electrolysis, as well as a monetary valuation of the associated greenhouse gas (GHG) emissions, is used to analyze the competitive position of electrolytic hydrogen in three specific locations with distinct electricity mix: Vancouver, Los Angeles and Paris. Using local electricity prices and fuel taxes, electrolytic hydrogen is found to be commercially viable in Vancouver and Paris. Hydrogen storage comes out as the most important technical issue. But more than any technical issue, electricity prices and fuel taxes emerge as the two dominant issues affecting the competitive position of electrolytic hydrogen. The monetary valuation of GHG emissions, based on a price of \$20/ton of CO_2, is found to be generally insufficient to tilt the balance in favor of electrolytic hydrogen.

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Nomenclature

AC/DC: alternative current/direct current

AWE: alkaline water electrolysis

CaFCP: California Fuel Cell Partnership

CB&H: Carbon Black and Hydrogen

CDM: clean development mechanism

CH_4: methane

CO: carbon monoxide

CO_2: carbon dioxide

CRF: capital recovery factor

CRF_e: effective capital recovery factor

CTFCA: Canadian Transportation Fuel Cell Alliance

CUTE: Clean Urban Transportation for Europe

DOE: United States Department of Energy

DTI: Directed Technologies Inc.

EPA: U.S. Environmental Protection Agency

FCV: fuel cell vehicle

GHG: greenhouse gas

H_2: hydrogen

H_2O: water

HHV: higher heating value

HTE: high temperature electrolysis

HVRA: hydrogen vehicle refuelling appliance

ICE: internal combustion engine

IET: international emission trading

IME: inorganic membrane electrolysis

IPCC: Intergovernmental Panel on Climate Change

KOH: potassium hydroxide

kW_e: kilowatt electric

LHV: lower heating value

LLNL: Lawrence Livermore National Laboratory

MEA: membrane electrode assembly

MeOH: methanol

mpgge: mile per US gallon gasoline equivalent

NEDO: New Energy and Industrial Technology Development Organization

NG: natural gas

NGASE: natural gas assisted steam electrolysis

NO_x: nitrous oxides

NREL: National Renewable Energy Laboratory

O&M: operation and maintenance

PEM: proton exchange membrane

PEMFC: proton exchange membrane fuel cell

POX: partial oxidation

PTFE: polytetrafluoroethylene

R&D: research and development

RFC: regenerative fuel cell

SMR: steam methane reforming

SOFC: solid oxide fuel cell

SPE: solid polymer electrolysis

STP: standard temperature and pressure

UNFCCC: United Nations Framework Convention on Climate Change

URFC: unitized regenerative fuel cell

WE-NET: World Energy Network

ZEC: Zero Emission Coal

ZEV: zero emission vehicle

Acknowledgements

The completion of this thesis marks a very important step in life for me. Of course, a thesis generally represents an academic achievement in itself, but to me the real learning experience has been on the personal level. Most graduate students who have attempted to write a thesis while working full-time understand how it can mysteriously transform itself over time from a stimulating research into a monster out of proportions. Well, in my case, it has taken longer than I would ever have imagined to finish it. But I finally get the impression that the monster has been tamed and that I can go on with my normal life. It has been quite a journey, and I have many people to thank for their understanding and support during these years.

First, I owe a big thanks to my thesis supervisor, Ned Djilali, who has always been extremely considerate. He quickly understood the kind of person I was, and provided all the autonomy, flexibility and encouragements that I needed, in addition to the type of advice that can normally be expected from a thesis supervisor.

Then, there is my family. I want to thank deeply Louise, François and Sarah for their indefectible support. They were kind enough to put up with my moods at all times, particularly during the last year. My mother Louise deserves a special mention for her devoted assistance during crucial periods. I also want to express my gratitude to close friends: Britta Bossel, Frankie-Lou Fuller, Walter Merida and Frédéric Dugré, who have been sources of inspiration and an important support throughout tough times.

Last but not least, I must thank Bruce Pridmore, Chris Ryan, Aileen McManamon, Walter Pickering and many former colleagues who have been very understanding and accommodating during my time with the National Research Council.

Finally, I keep a rich impression of the many people I have had the chance to know more personally at the Institute for Integrated Energy Systems (IESVic). Ned Djilali, David Scott, MacMurray Whale and Ged McLean in particular have contributed, by their teaching and their enthusiasm, to shape my vision of future energy systems for a better world. All these people have fed my ambitions to become an active player in the profound transformations towards a sustainable world, where technology and the environment can coexist in harmony.

Chapter 1 – Introduction

1.1 Rationale

Severe degradation of urban air quality in a growing number of cities around the globe has prompted the adoption of stricter legislation to reduce polluting emissions, particularly from transportation. The State of California has been a leader in this respect, with the introduction of its 1989 legislation requiring that 2% of total vehicle sales in 1998 and 10% in 2003 be zero emission vehicles (ZEV) [1]. Although these targets have been revised a few times since, the legislation triggered more intense efforts in the development of cleaner energy technologies such as fuel cells, advanced batteries and hybrid vehicles, to significantly reduce polluting emissions from transportation.

As a result, fuel cells and hydrogen have been at the forefront of technology developments for a few years now, not only in transportation but across the whole energy sector. The technology has attracted sizeable investments and achieved significant technical progress. It is receiving growing support from governments and the private sector, in leading countries like the United States, Canada, Japan or Germany [2], but also in less technologically advanced countries facing serious environmental problems, like China [3]. Today, a wide spectrum of industries are involved concretely in fuel cell activities: carmakers, oil companies, power utilities, portable electronics, etc.

Immediate concerns about the effects of toxic air pollutants may have been a trigger for the development of cleaner energy technologies like fuel cells, but another type of pollution linked to transportation may have much more profound repercussions in the long term: the so-called greenhouse gas (GHG) emissions. Attributable primarily to the combustion of fossil fuels, GHG emissions from anthropological sources have become a serious threat to ecosystems and future generations because their effects are felt globally and on a much longer time scale. Global warming caused by increasing levels of GHG in the atmosphere could lead to climate disruption and a multitude of adverse consequences, often irreversible. The issue gained credibility during the 1990s and resulted in the much publicized Kyoto Protocol in 1997. Aimed at reducing GHG emissions internationally, the Protocol constitutes a first step in the right direction, but curbing GHG emissions to sustainable levels will require fundamental changes in energy systems.

Fuel cell vehicles (FCV) have the potential to completely eliminate harmful *tailpipe* emissions without compromising vehicle performance or range. However, their ability to cut back GHG emissions globally depends largely on the choice of fuel and its distribution infrastructure. Hydrogen is the fuel required for the fuel cells per se, but it can be obtained from a variety of sources or extracted onboard from a hydrocarbon fuel. The choice of fuel ought to maximize the long term benefits of replacing internal combustion engine (ICE) vehicles by FCVs, particularly with respect to GHG emissions. On the other hand, a successful strategy for introducing FCVs must minimize the technical and economic barriers that could prohibit or significantly delay the adoption of FCVs. That is why fuelling is such a central issue in the development of fuel cell systems in transportation.

Hydrogen, methanol and gasoline are currently the three most seriously considered fuel options. Primarily because of economic considerations, they would all be largely produced from fossil fuel sources in the near future. One problem in using fossil fuels as a feedstock is their associated emissions, in particular GHG. Hydrogen generated from fossil fuels, either onboard vehicles or at a stationary plant, invariably releases carbon-containing byproducts, generally in the form of CO_2. Even hydrogen produced from stationary steam reforming of natural gas, considered as the economically feasible option with the most significant reductions in GHG emissions, still emits 30-60% of the GHG emissions from a gasoline ICE vehicle, when used in a FCV [4-5].

Hydrogen from water electrolysis constitutes an inherently more flexible option with respect to the energy input required and the associated GHG emissions. Electrolysis can make use of the electrical and water infrastructure already available in many areas. It also provides access to nuclear and renewable energy sources, which have very low GHG emissions. Moreover, an interesting synergy between similar aspects of water electrolysis and fuel cell technologies could have a noticeable impact on the development and cost of the electrolytic hydrogen fuelling option. Electrolyzers can be scaled-down relatively easily compared to other options, which may be an important advantage for the smooth market penetration of FCVs.

Accordingly, some electrolyzer companies have adopted a product development strategy that emphasizes the decentralized production of electrolytic hydrogen for the future FCV market [6-7].

The fundamental goal of the present thesis is to identify key technical and economic parameters that offer opportunities to maximize the competitive position of decentralized electrolytic hydrogen for FCVs. To do so, a model was developed that incorporates not only the various capital and energy costs, but also a monetary valuation of the associated GHG emissions. A sensitivity analysis was then performed to quantify the impact of various issues from three increasingly broader perspectives, namely: technical, economic and "comparative". In the end, this integrated analysis provides a tool for directing more effectively the actions required to improve the competitive position of electrolytic hydrogen for FCVs.

1.2 Fuel Cell Vehicles

Three broad approaches are being discussed these days when speaking of cleaner light-duty vehicles: hybrids, battery electric, and fuel cell vehicles (FCV).

Hybrids generally refer to a combination of internal combustion engine (ICE) and batteries to improve the overall energy efficiency of the vehicle. However, all of the energy in a hybrid car still comes exclusively from the combusted fuel, part of which is used to recharge the batteries. The relative market success of introductory hybrid cars like the Toyota Prius and Honda Insight have prompted most carmakers to announce the commercialization of several more hybrid models in the coming years. Even though the hybrid approach can reduce polluting emissions sensibly, mostly due to an increase in vehicle mileage of 20-40%, it remains a partial and temporary solution for the long term.

Battery electric vehicles rely entirely on a bank of batteries to store electricity and use it to power the vehicle. In this case, the actual source of energy depends on the electricity mix of the recharging station. The main practical problems associated with battery electric vehicles are a long recharging time and a limited range due to the much lower energy density of batteries compared to hydrocarbon fuels.

FCVs are also electrically powered like battery electric vehicles. The difference lies in that the electricity is produced onboard by fuel cells. A fuel cell is an electrochemical energy conversion device that converts the chemical energy of a fuel into electricity and heat, without combustion. When the fuel is pure hydrogen and the oxidant is oxygen from the air, there are no tailpipe emissions other than water. A FCV can therefore combine the advantages of a battery electric vehicle in terms of tailpipe emissions, and those of an ICE vehicle in terms of energy density and ease of refuelling. Figure 1.1 shows an example of a hydrogen fuel cell system for light-duty vehicles [8].

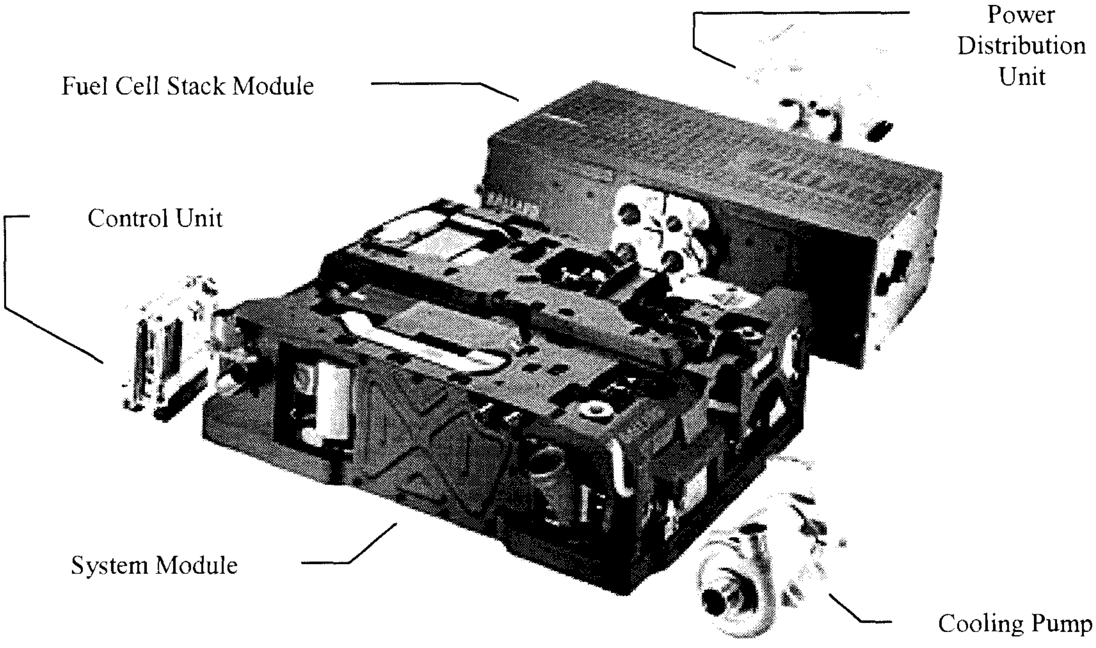

Figure 1.1: 80 kW light-duty fuel cell engine developed by Ballard Power Systems [8].

The type of fuel cell favored by all major carmakers is the proton exchange membrane fuel cell (PEMFC). Because they are quite sensitive to contaminants, particularly carbon monoxide, PEMFCs require relatively pure hydrogen as a fuel. They cannot use other hydrocarbon fuels directly either. Therefore, it leaves two possible fuel strategies: either onboard hydrogen storage or onboard processing of a liquid fuel like gasoline or methanol to extract hydrogen. Note that the latter option adds further complexity to the system and results in some CO_2 and other trace emissions from the vehicle, along with water.

Although most experts agree that mass commercialization of light-duty FCVs is still years away, much progress has been achieved over the last five years in terms of system integration, performance and cost reduction. A growing number of prototypes have demonstrated the feasibility of FCVs running on hydrogen, methanol and even gasoline. Between 1998 and 2003, the cumulative number of light-duty FCVs and fuel cell buses built and operated worldwide have grown respectively from 40 to 300, and from 15 to 65 [9-10]. FCVs have even inspired completely new vehicle configurations like the GM Hy-wire named for its combination of hydrogen fuel cell and drive-by-wire technology. The whole propulsion and control systems are contained within a 28-centimer thick skateboard-like chassis, maximizing the interior space for five occupants and their cargo [11].

Demonstration projects involving multiple partners provide an advantageous context to accelerate the development and introduction of FCVs while sharing the risks. Notable examples of such projects are the California Fuel Cell Partnership (CaFCP) [12] and the CUTE project in Europe (Clean Urban Transport for Europe). With nearly 30 partners, including carmakers, oil companies and government agencies, the CaFCP has placed close to 60 FCVs on California roads so far, and eight hydrogen or methanol fuelling stations. The governor of the State, Arnold Schwarzenegger recently announced a plan to establish a network of 200 hydrogen fuelling stations throughout California by 2010 [13]. In Europe, the CUTE project is putting a fleet of 27 hydrogen fuel cell buses in commercial operation in nine European cities.

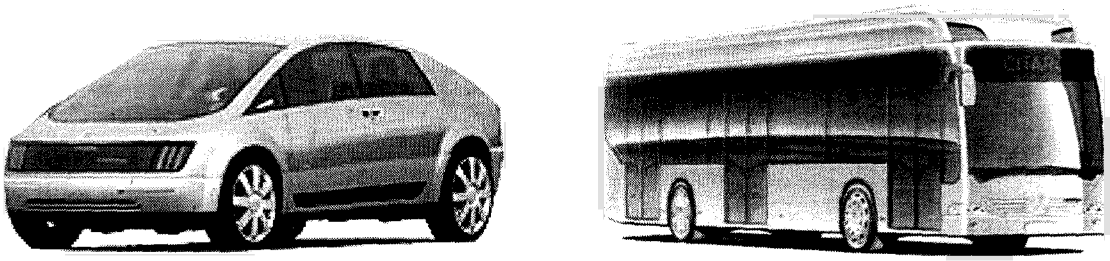

Figure 1.2: Examples of fuel cell vehicles. Hy-wire fuel cell car developed by General Motors [11] and fuel cell bus model produced by DaimlerChrysler for the CUTE project in Europe [14].

1.3 Greenhouse Gases and Climate Change

The Earth's atmosphere is comprised of naturally occurring greenhouse gases (GHGs), such as water vapor (H_2O), carbon dioxide (CO_2), nitrous oxides (NO_x) and methane (CH_4). These gases form an insulating envelope around the planet that traps a portion of the heat received from the Sun, which would otherwise be reflected back into space. Without this essential envelope of GHGs, the Earth's mean temperature would be approximately 30°C lower, and the planet would be unable to sustain life [15].

Based on scientific evidence, a strong correlation exists between atmospheric CO_2 level (by far the dominant GHG) and temperature [16]. For thousands of years, a natural equilibrium between sources and sinks of CO_2 has kept the pre-industrial atmospheric concentration of CO_2 at about 280 ppmv (parts per million volume). Analyses of air trapped in the major icecaps show that the range of CO_2 concentration has stayed between 180 and 280 ppmv over the period of record of the last 400,000 years. Since the beginning of the Industrial Revolution however, the concentration of CO_2 in the atmosphere has risen about 33% to 371 ppmv (in 2001), most of that rise occurring in the last 40 years. As a result of growing GHG emissions from anthropogenic sources, largely due to the burning of fossil fuels, the current atmospheric concentration and rate of increase of CO_2 are completely without precedent for at least the last 400,000 years [17].

Since the mean lifetime of CO_2 in the atmosphere is in the order of 100-150 years, the effects of today's emissions will be felt well into the next century. The Intergovernmental Panel on Climate Change (IPCC) has developed six emissions scenarios (IS92) to cover the range of possible CO_2 emissions patterns until 2100. They reflect various combinations of population and economic growth rates as well as certain fossil fuel constraints. One striking observation is that even the most optimistic scenario predicts that CO_2 concentration should reach 500 ppmv sometime around the middle of this century, regardless of the rate of emissions reduction. (Figure 1.3) [17].

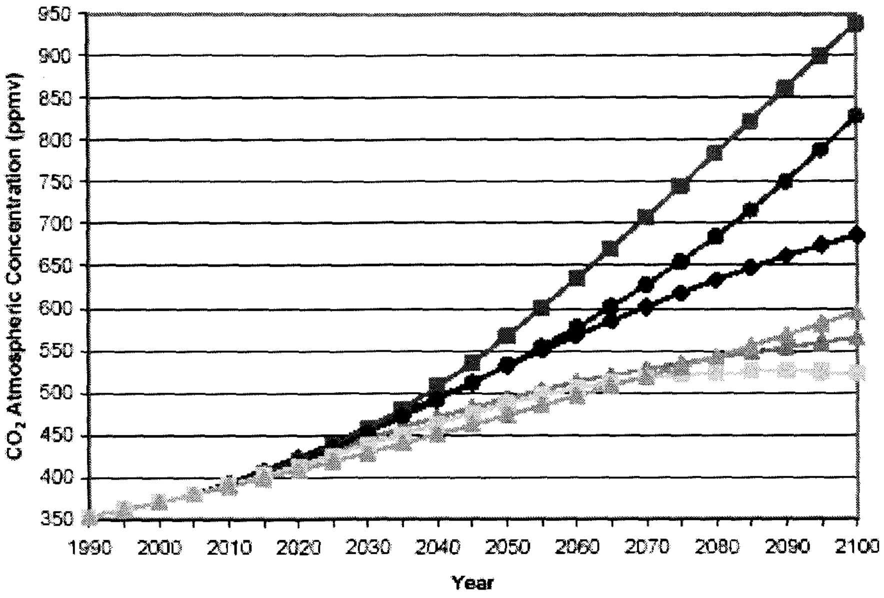

Figure 1.3: IPCC estimates of CO_2 atmospheric concentration to 2100 for their six marker scenarios (IS92). [17]

Our only chance to stabilize CO_2 atmospheric concentration at double pre-industrial levels is to ensure that by mid-century, the technologies and policies required to mitigate climate change are widespread. In the energy sector, it means that nearly all new power generation and transportation by then should have extremely low or zero GHG emissions. That is true not only for industrialized countries that should lead the way, but also for developing countries where most of the growth in energy use will take place, keeping in mind that developing countries are expected to increase their GHG emissions to levels much closer to industrialized countries. For example, CO_2 emissions in 1995 were of nearly 20 tons per capita in the USA vs. 3 tons per capita in China [15].

The imperative for actions to reduce GHG emissions lies in the magnitude and irreversibility of long term consequences related to global warming. The effects of global warming occur on a global scale rather than locally or regionally as in the case of particulate emissions or acid rain. Small variations in global temperature could lead to broader climate change patterns, raise sea levels, alter forest and crops yields, and reduce potable water supplies [18]. Entire ecosystems could be altered irreversibly, and densely populated coastal areas could be flooded periodically or permanently. Some adaptation to the consequences of climate changes is possible, but much is unpredictable, so common sense dictates a cautious approach.

Transportation is responsible for approximately 26% of GHG emissions in Canada [19], a share that is representative of most industrialized countries. Therefore, any long term plan to curtail GHG emissions must include actions in the transportation sector.

Recognizing the threat posed by rising concentrations of GHGs in the atmosphere, 150 nations from around the world signed the United Nations Framework Convention on Climate Change (UNFCCC) in 1992, to cut GHG emissions on a voluntary basis to 1990 levels by 2000. In 1997, the parties to the UNFCCC met in Kyoto and negotiated a protocol that established legally binding limits or reductions in GHGs for industrialized countries.

The Kyoto Protocol also proposed flexible mechanisms to help countries achieve their emission reduction targets. International Emission Trading (IET) allows industrialized countries to trade emission reduction credits among themselves, while the Clean Development Mechanism (CDM) enables them to finance emission reduction projects in other industrialized or developing countries. But even if the Kyoto Protocol is adopted and fully implemented, it merely represents the beginning of a solution to the GHG problem, as it would slow down global warming only slightly, approximately 4-7% or 0.1°C to 0.2 °C by 2100 [15].

An embryonic market for trading CO_2 emission reductions has already started and it is anticipated to become one of the largest commodity markets in the world. A fair amount of economic modeling has been completed by government entities, industry-sponsored consulting groups, academic institutions and national laboratories, predicting values for GHG reductions in the range US$25.00 to $150.00 per ton of CO_2 equivalent. Most of the transactions that have occurred so far are more in the US$3.00 - $20.00 range, prices significantly lower than the projected ones, primarily due to a discount for regulatory risks [20]. The projected and actual monetary values assigned to CO2 emission reductions clearly constitute an additional tool for informed policy.

1.4 Hydrogen Production Technologies

Hydrogen may be produced from a variety of feedstocks, using several technologies. They can be divided in four broad categories: hydrocarbon based technologies (fossil fuels and biomass), water electrolysis, biological production and thermochemical cycles. Some are well established technologies while others are still at the development stage.

In practice, only fossil fuels processing and water electrolysis are commercial methods for producing hydrogen. For large scale production, the economics generally favor hydrogen from fossil fuels. Since the bulk of industrial hydrogen produced today is used in large chemical plants for petroleum refining, ammonia and methanol synthesis, fossil fuels are by far the dominant feedstock. Water electrolysis is more suitable for industry sectors that require very high purity hydrogen, like metallurgy, electronics and pharmaceuticals. Of the 45 million tonnes or so of hydrogen produced worldwide annually, approximately 96% comes from fossil fuel processing (48% natural gas, 30% oil, 18% coal) and only 4% from water electrolysis [21]. An interesting observation is that the current world production of hydrogen corresponds to the fuel requirements of some 200 million light-duty FCVs, or about one third of the global number of light-duty vehicles on the road today.

The main processes employed in industrial hydrogen production are steam reforming, (SMR - steam methane reforming), partial oxidation (POX) and combinations of the two. In these processes, the hydrocarbon fuel reacts with either water or oxygen to form carbon monoxide (CO) and hydrogen (H_2). In both cases, the resulting CO is further reacted with water to produce additional H_2 and CO_2 (water shift reaction). Notice that for SMR and POX, a significant portion of the actual hydrogen produced comes from water, generally over 50%. Pyrolytic cracking is another interesting approach for hydrocarbons as it directly splits the feedstock into hydrogen and a pure carbon product (carbon black). It is characterized however by a low feedstock utilization and high emissions [21].

Although it now occupies a modest share of the hydrogen production market, water electrolysis is in fact the oldest hydrogen production technology. Electrolytic water splitting was first demonstrated by Nicholson and Carlisle in 1800, in the early days of the industrial revolution. Yet, it took about a century before it was introduced as a useful industrial way of producing hydrogen and oxygen. By 1900, about 400 industrial electrolyzers were in operation [22]. During most of the twentieth century, the general trend has been to increase the size of electrolyzers, up to 100 MW electrical input or more to take advantage of economies of scale [23]. In recent years, advances in fuel cell technology have stimulated a renewed interest in water electrolysis, as a possible avenue to provide hydrogen fuel; but with more emphasis on smaller electrolyzer plants, better adapted to a decentralized hydrogen production infrastructure.

An important disadvantage of the present practice of hydrogen production from fossil fuels is that the carbon contained in the feedstock is released in the atmosphere as CO_2. The amounts released vary from 9 to 18 kilograms of CO_2 per kilogram of hydrogen produced, for the range of natural gas to coal as raw materials [21]. These emissions could be avoided or at least substantially reduced by sequestering the CO_2. Sequestration techniques such as injection into underground reservoirs and ocean storage are being researched throughout the world, and recent studies show that the increase of hydrogen cost could be moderate, at least for hydrogen produced from natural gas. Beside CO_2 sequestration, promising technologies to produce CO_2-free hydrogen from fossil fuels are envisioned, like the Kvaerner "CB & H" process for natural gas [24] and the "ZEC" technology (zero-emission coal) for coal [25]. The former is a plasma arc process for the pyrolytic cracking of natural gas producing only pure carbon black and hydrogen (CB & H). The latter generates hydrogen from coal and a stream of CO_2 that is disposed of permanently through a process that forms stable solid mineral carbonates.

Ultimately, hydrogen ought to be produced on a large scale by alternative methods that reduce our dependence on fossil fuels. Several of them rely on water electrolysis as the technology of choice to transform the "energy currency" electricity into hydrogen. Electricity can come from a CO_2-neutral source like biomass, or other energy sources with very low associated GHG emissions like nuclear and renewable energy (hydroelectric, geothermal, solar, wind...). Nuclear energy presents a particular interest, not only for the production of CO_2-free electrolytic hydrogen on a large scale, but also because heat generated in nuclear plants can be exploited in thermochemical cycles. In such a cycle, water splitting is the net result of a series of chemical reactions that take place at much lower temperatures (around 900°C) than direct thermal water splitting (2500°C) [26]. Biological production techniques, mainly biophotolysis of water and decomposition of organic compounds by enzymes, are probably among the less advanced options, but quite promising in the long term due to rapid progress in genetics. The wide array of specific hydrogen production technologies makes it impossible to touch on all of them here, but extensive literature on the latest developments is readily available [27].

If hydrogen is to be the fuel used in FCVs, current trends suggest that the most likely production technologies will be decentralized SMR and water electrolysis, at least for the initial market penetration phase of FCVs. Cost comparison studies between various hydrogen production methods, specifically adapted to the introduction of FCVs tend to favor decentralized SMR wherever natural gas is available [28-29]. But as the market develops, policymakers and society in general will need to balance economic considerations with environmental ones, like the need for major CO_2 reductions, in directing the future deployment of a hydrogen production infrastructure.

1.5 Factors Influencing the Development of a Refuelling Infrastructure

A combination of technical, economic and political considerations will influence the directions taken in the transition to an appropriate refuelling infrastructure for FCVs.

1.5.1 Fuel Options

The trade-offs associated with each fuel option for FCVs can be summarized as follows. Gasoline offers access to an existing fuelling infrastructure but requires a complex onboard fuel processing system that poses major technical challenges. Methanol offers the convenience of a liquid fuel and reduced complexity in the fuel processing system, but is seen as an intermediate solution. If hydrogen remains the preferred fuel for the long term, car manufacturers and fuel providers may not risk getting involved in an intermediate fuel infrastructure. Finally, hydrogen appears to be the cleanest option [30-31], but it requires a completely new fuel infrastructure and poses challenges for its storage. So technical issues like processing of liquid hydrocarbon fuels and hydrogen storage will play a critical role in the choice and timing of the transition to the most appropriate fuel option for FCVs.

1.5.2 Trends in Energy Markets

Decentralization is a general trend that is already happening to some extent in power generation. The growing market share of distributed power generation, such as small efficient natural gas turbines (and eventually stationary fuel cells), indicates a progressive shift away from large coal or nuclear power plants. Although these smaller power generation units are often more expensive than larger ones (per kilowatt-hour produced), they offer the advantages of shorter planning and construction times, and are consequently more resilient to change.

Resilience to change may also favor decentralization in the development of a refuelling infrastructure for FCVs. Even the most aggressive introduction scenarios suggest that only a small fraction of all vehicles on the road by 2020 will be FCVs. Figure 1.4 shows one such scenario with the world market penetration of FCVs reaching 50% by 2015 and 75% by 2020. This reality emphasizes the need for a decentralized fuelling infrastructure, at least during a transition period from gasoline to hydrogen.

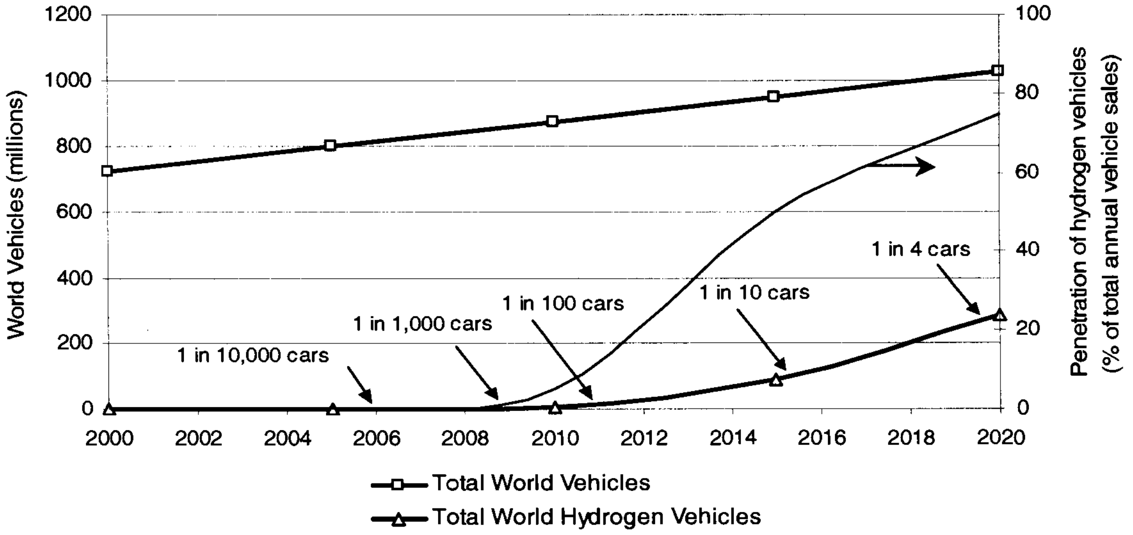

Figure 1.4: Optimistic growth rate of hydrogen cars in world market (adapted from [32]).

Deregulation of the electricity market in many jurisdictions is another trend that could have a positive impact on the cost of electricity. Even though the market deregulation experience in California has shown otherwise so far, it is believed that the market will keep moving towards open access and efficient pricing, ultimately resulting in lower electricity rates and real time pricing.

1.5.3 Externalities

Most current means of producing and utilizing energy cause damages to human health, natural ecosystems, and the built environment, which are difficult to determine, let alone to quantify in monetary terms. As a result, these damages are either ignored or valued at zero in traditional financial assessments. They are treated as external costs, i.e. they are not reflected in the market price of energy. They are part of the "externalities" of energy systems. In economic theory, externalities are defined as: "the costs and benefits which arise when the social or economic activities of one group of people have an impact on another, and when the first group fail to account for their impacts" [33].

The growing public concern with environmental issues has been pushing policymakers to recognize these external costs of energy. The interest for some new accounting framework that allows the internalization of externalities has led to "ExternE" – one such framework jointly developed over several years by the European Commission and the US Department of Energy (DOE) [33]. The extent to which these externalities (namely the effects of GHG emissions) will be recognized in coming years will clearly influence business decisions related to fuel options for future vehicles.

1.5.4 Energy Security

With the growing dependence of the United States, Europe and East Asia on imported oil from the Middle East, energy security is a factor that could play an important role in the support for the development of alternative energy sources.

The cost of maintaining a military presence in the Middle East, to ensure stability of the region and access to oil, is also an economic argument (particularly for the United States) to support the development of energy systems using indigenous energy sources.

1.6 Focus and Methodology of this Study

This research is focused on decentralized electrolysis, i.e. small refuelling stations that produce hydrogen on-site to support the needs of 2 to 1000 FCVs, as opposed to large-scale electrolysis plants. As pointed out earlier, even if FCVs successfully penetrate mass markets, it is almost certain that hydrogen-fuelled FCVs will represent a minority of vehicles on the road in most locations for at least the next 20-25 years. During this transitional period, decentralized hydrogen production could be the most flexible and advantageous option. The majority of studies done prior to the mid-1990s on the production of electrolytic hydrogen considered a large-scale centralized approach, similar to the production of gasoline in oil refineries [34-35]. Some of these centralized schemes may prove to be more economical once FCVs are widespread.

To understand where this technology fits in a broader picture, a basic comprehension of the architecture of energy systems is helpful. Any energy system can be broken down conceptually into a five-link chain that goes from the service that is needed to the energy source used to provide it. Even though the direction of the energy flow is from the source to the service, the chain really starts with the service because this is what drives the choices in the other links of the chain [36] (see figure 1.5 below).

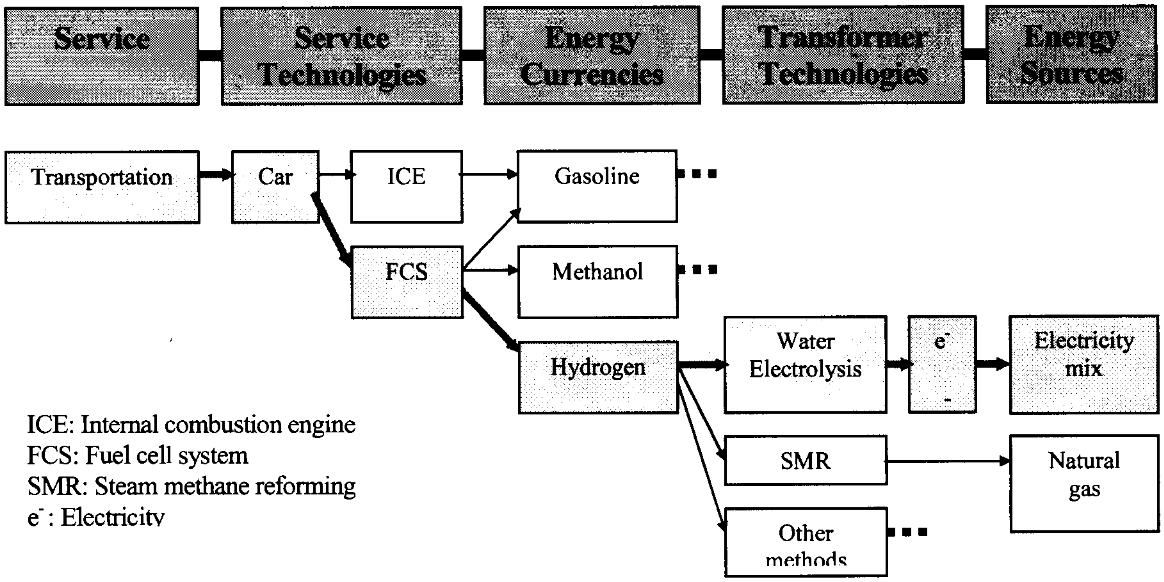

Figure 1.5: Path analyzed in reference to the architecture of energy systems.

In the context of this thesis, the *service* starting the chain is land transportation. The specific "*service technologies*" of interest to provide it are the car and its propulsion system. For the fuel cell system option, attention is directed at one of the "*energy currencies*" to fuel it: hydrogen. Then, among the various "*transformer technologies*" capable of delivering this hydrogen, the focus is on water electrolysis. Since electrolysis necessitates an electricity input (an intermediate energy currency), multiple *energy sources* (uranium, wind, sun...) can be used to produce it. Figure 1.5 shows the resulting chain of interest from transportation to the electricity mix. Here, the box "electricity mix" refers to all possible combinations of energy sources used with the appropriate transformer technologies to generate electricity.

The main objective of this thesis is to provide a tool that will assist not only engineers, but also business people and policymakers, in directing their actions effectively to improve the competitive position of electrolytic hydrogen as a fuel. To this end, an analysis from three increasingly broader perspectives is proposed. It starts with the technical aspect, which is typically the domain of engineers. Then it considers an economic perspective, particularly financial and market aspects, most relevant to a business outlook. Finally, it addresses what is called here the "comparative" aspect, i.e. issues like taxes, incentives/subsidies which can influence the competitive position of a fuel option versus the others. This third aspect is particularly relevant to policymakers, who can use various tools to catalyze change, and ensure a level playing field for hydrogen as a fuel option. Figure 1.6 shows a schematic view of the three perspectives considered in this analysis.

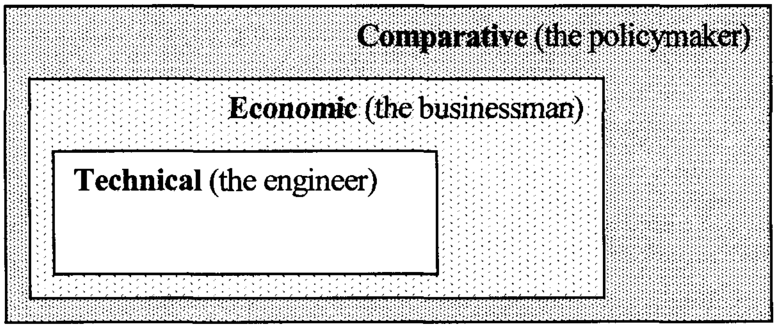

Figure 1.6: Aspects of decentralized water electrolysis investigated.

A more thorough study of any of these three aspects could have justified a thesis of its own, but the value here lies more in the integration of perspectives and the qualitative conclusions that can be drawn from this exercise. In particular, this approach gives the opportunity to compare the potential impact of different technical improvements, not only between themselves, but also with issues in the other two aspects considered.

A model was developed in Microsoft Excel to allow the quantitative comparison of actions in each of the three perspectives. The main parameter of the model is the unit cost of hydrogen ($/kg), which is used as a common basis for a sensitivity analysis. The impact of each parameter is translated in economic terms, affecting the unit cost of hydrogen. The model developed builds on previous modeling studies, and the base case used for sensitivity analysis is adapted from previous studies as well. The model's structure is described in details in Chapter 3, along with its validation procedure.

When electrolytic hydrogen is compared to other fuel options, comparison is made on a "fuel-cost-per-kilometer" basis. This constitutes a better approach than comparison on an energy-content basis in this case, because the fuel cost per kilometer is what the consumer pays. For example, even if electrolytic hydrogen costs twice as much as gasoline on an energy-content basis, the fuel cost per kilometer could be the same if the vehicle's propulsion system is twice as efficient.

The analysis section proceeds in two steps. First, a sensitivity analysis is performed following the structure of the cost model, and the parameters are categorized under the technical, economic or comparative aspect. In the second part of the analysis, the parameters are grouped and translated into "issues" that influence the price of electrolytic hydrogen or its competitive position. Actual data from three different cities is used in that section to illustrate the impact of site-specific information. Finally, the results of the analysis are discussed and recommendations are made.

There are obviously some caveats to this study, which should be taken into account when interpreting the results. They relate to some assumptions made in the context of this research and inherent limitations of the model. Important ones are listed here:

- *This study makes comparisons of fuel costs only, independently of the capital and operating costs of the vehicle.* In other words, the cost model developed here decouples the fuel cost from other vehicle costs. In reality, for FCVs to compete with ICE vehicles on an economic basis, what really matters is that the life-cycle costs of owning and operating the vehicle be similar. Fuel costs account for approximately 8% or less of the total cost of owning and operating a car [4]. However, it is very likely that most consumers would insist on comparable fuel prices at the pump. So consumer behavior is an important factor to justify the comparison of fuel costs separately. If the life-cycle costs of hydrogen-fuelled FCVs are shown to be comparable to those of an ICE vehicle, there are mechanisms to allow the adjustment of hydrogen prices at a level that satisfies the consumer.

- *A theoretical monetary valuation is given to CO_2 to calculate the magnitude of the surtax or credit assigned to electrolytic hydrogen.* This is a convenient simplification to obtain a first order assessment of the impact of CO_2. A more representative approach would require taking into account marginal costs associated with the application of tax/credit measures. Also, the value assigned to CO_2 does not have to always reflect the market price of CO_2 emissions. For instance, a much higher credit for low CO_2 emissions granted initially could accelerate the introduction of FCVs, before getting back to the market price of CO_2 emissions, once FCVs have been introduced.
- *The model and results analysis both present a number of limitations.* Several couplings are not reflected explicitly in the model. For example, a larger electrolyzer station could possibly benefit from lower electricity rates than a smaller one, but this is not accounted for in the model. Also, the model assumes that an electrolyzer station functions at its nominal production capacity, which tends to minimize its capital price by amortizing it on a larger volume of hydrogen than a more realistic case. In the results analysis, the impact of various issues depends in part on the estimated range of variation for the corresponding parameters. All these elements are further discussed in the analysis portion of Chapter 4.

1.7 Prior Work

At the time this research was started, much valuable work had already been published about the technical, economic, environmental and social implications of fuel choices for FCVs. Since then, the growing interest of governments and the private sector for fuel cells has stimulated a lot more research and thorough studies on these issues. A representative sample is mentioned here.

1.7.1 Fuel choices for FCVs

Thomas et al. from Directed Technologies Inc. (DTI) have performed a substantial amount of work on fuel options for FCVs, mostly during the second half of the 1990's, under contract with the US Department of Energy (DOE) [4, 37-38]. The overall results emerging from their work seem to be that onboard hydrogen is the preferred fuel option for FCVs, and that hydrogen produced from natural gas reforming (small-scale SMR) presents the most interesting opportunity. In fact, some directors at DTI later started a company called H_2Gen, whose main product is a small-scale SMR [39].

Another group that has been active for several years in fuel infrastructure issues for FCVs is the Center for Energy and Environmental Studies led by Joan M. Ogden at Princeton University. They have covered a wide array of issues related to a hydrogen fuel infrastructure [29,40].

Organizations such as the California Fuel Cell Partnership (CaFCP) in the United States and the Canadian Transportation Fuel Cell Alliance (CTFCA) in Canada have contributed to the literature on the subject, with several reports from expert panels. One of these reports written in 2001 for the CaFCP provides exhaustive information on the options of hydrogen, methanol, gasoline and ethanol fuel [31]. A more recent report produced by Ernst & Young for Natural Resources Canada in 2003 concludes that multiple hydrogen pathways in Canada could compete economically with gasoline and diesel, with a combination of emission taxes and excise tax exemptions [41].

Finally, a comprehensive study conducted in 2001 by General Motors, Argonne National Laboratory and energy partners BP, ExxonMobil and Shell, concluded that gasoline or a gasoline-derived fuel is the best option for FCVs in the near-term and that hydrogen is clearly the preferred option for the long-term. The study covered 75 fuel pathways and reinforced GM's philosophy that there is no need for an intermediate fuel infrastructure such as methanol or compressed natural gas [11].

1.7.2 The Electrolysis Option

The Electrolyser Corporation (now Stuart Energy Systems) produced a substantial report for the Ford Motor Company in 1996, focusing on the electrolysis option for the FCV fuel supply infrastructure. The report covers a broad range of issues from electricity supply strategies to safety analysis of FCV fuelling stations [42].

Another report by DTI for the National Renewable Energy Laboratory (NREL) investigated the electrolytic hydrogen option and analyzed the potential for low-cost electricity in the United States. The study showed that there is potential for electrolytic hydrogen to compete with gasoline in many parts of the country, based on off-peak electricity rates [43].

Several studies that have been reviewed look at the possible integration of renewable energy sources with water electrolysis or other technologies to produce hydrogen. Mann et al. from NREL are a noteworthy reference for literature on the production of hydrogen from renewable resources [44].

1.7.3 The Influence of Greenhouse Gas Emissions

In light of the implications of the Kyoto Protocol and the issue of GHG emissions in the long-term, a lot of work has been done on well-to-wheel GHG emissions from the various fuel pathways. Most of the studies mentioned in the prior work section about fuel choices (1.7.1) address the GHG issue.

Two studies produced in Canada on the subject are particularly thorough [45-46]. The first one was produced by the Pembina Institute for Appropriate Development and presents a detailed assessment of the life-cycle value of fuel supply options for FCVs in Canada. The second one, prepared for Fuel Cells Canada, used Natural Resources Canada's model called "GHGenius" to analyze the life-cycle energy use and GHG emissions of fifty fuel pathways for transportation. Both studies emphasize the wide range of GHG emissions that can result from different hydrogen production pathways, from much lower to much higher GHG emissions than gasoline used in ICE vehicles.

Energy companies like Shell, BP and ExxonMobil have also participated to some studies of GHG emissions from various fuel options, or produced their own [30, 47]. They all recognize the potential of hydrogen fuel to reduce GHG emissions substantially, but only in a limited set of production pathways.

Chapter 2 – Water Electrolysis Background

2.1 Principles

The production of hydrogen by the electrolysis of water is, in principle, very simple. It is a process by which electricity is used to decompose water into its components – gaseous hydrogen and oxygen. The overall reaction is:

$$H_2O + energy \Rightarrow H_2 + \tfrac{1}{2}O_2 \tag{2.1}$$

A typical electrolysis cell[1] is composed of two electronic conductors (a positively charged electrode – the anode, and a negatively charged electrode – the cathode) in contact with an ionic conductor, the electrolyte. When an electric direct current (DC) is passed through such a cell containing water, the water molecules may be split into hydrogen and oxygen. The voltage required to "pump" the electrons (e^-) that make up this direct current is largely determined by thermodynamic considerations. The principles of an electrolysis cell are shown in figure 2.1 for an alkaline electrolyte.

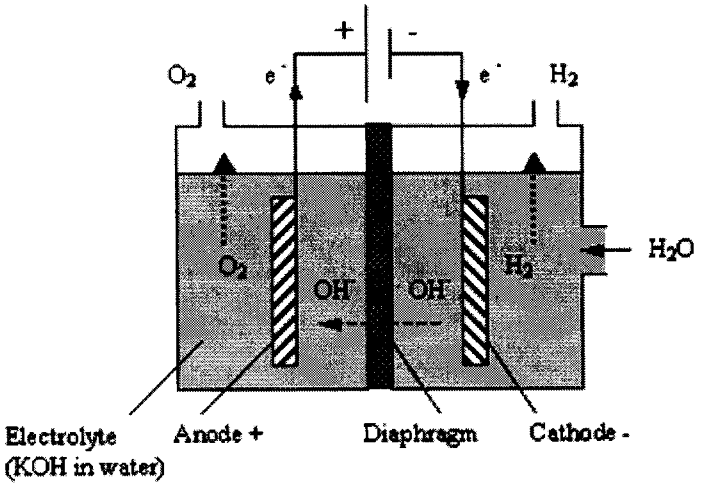

Figure 2.1: Principle of alkaline water electrolysis (AWE).

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[1] A cell commonly refers to the basic elements making up a single electrochemical circuit.

Although the discovery of electrolytic water splitting was done in an acidic solution, alkaline electrolytes have been preferred in actual applications, mainly because of lesser corrosion problems. Large-scale electrolyzers commercialized during the twentieth century are all based on conventional alkaline water electrolysis (AWE). However, other promising types of electrolyte exist like those used for solid polymer electrolysis (SPE) and high temperature electrolysis (HTE). The basic principles and reactions for each of these three types of electrolyte are presented below.

2.1.1 Alkaline Water Electrolysis (AWE)

Since water is a very poor ionic conductor, the electrolyte has to contain other components to obtain a reasonable conductivity. For alkaline electrolysis, potassium hydroxide (KOH) is the most used component given its good conductivity. The KOH electrolyte typically has a concentration of 25-30% (by weight). In conventional AWE, electrolysis takes place at a temperature around 80 °C and a pressure in the range of 1 to 30 bar [22], although higher temperatures and pressures can now be achieved with advanced AWE technology.

The basic reactions at the two electrodes are given below with a net overall reaction equivalent to reaction 2.1.

Cathode: $$2H_2O + 2e^- \Rightarrow H_2 + 2OH^- \tag{2.2}$$

Anode: $$2OH^- \Rightarrow \tfrac{1}{2}O_2 + H_2O + 2e^- \tag{2.3}$$

Overall reaction: $$H_2O \Rightarrow H_2 + \tfrac{1}{2}O_2$$

Using a KOH solution as an example (and adjusting the stoichiometric coefficients to see the net reaction more clearly), the reaction at the cathode proceeds as follows:

$$2K^+ + 2e^- \Rightarrow 2K \tag{2.4}$$

$$2K + 2H_2O \Rightarrow 2K^+ + 2H + 2OH^- \tag{2.5}$$

$$H + H \Rightarrow H_2 \tag{2.6}$$

Net cathode reaction: $$2H_2O + 2e^- \Rightarrow H_2 + 2OH^-$$

The reaction is initiated when positively charged potassium ions are reduced (reaction 2.4) and subsequently react with water to form hydrogen atoms and hydroxyl ions (reaction 2.5). The highly reactive hydrogen atoms then bond to the metal of the cathode. Hydrogen atoms combine in pairs at the surface of the cathode to form hydrogen molecules, which leave the electrode as a gas (reaction 2.6) [48]. As expected, the net cathode reaction is identical to reaction 2.2.

At the anode, a reaction similar to the one at the cathode occurs, producing oxygen:

$$2OH^- \Rightarrow 2OH + 2e^- \qquad (2.7)$$

$$2OH \Rightarrow H_2O + O \qquad (2.8)$$

$$\tfrac{1}{2}O + \tfrac{1}{2}O \Rightarrow \tfrac{1}{2}O_2 \qquad (2.9)$$

Net anode reaction: $2OH^- \Rightarrow \tfrac{1}{2}O_2 + H_2O + 2e^-$

The net result of sub-reactions 2.7, 2.8 and 2.9 is identical to the anode reaction 2.3. Oxygen molecules are released as a gas at the anode, just like hydrogen at the cathode.

For AWE to proceed steadily, hydroxyl ions (OH^-) must continuously migrate from the cathode to the anode, in a way that prevents the intermixing of hydrogen and oxygen. To this end, a separator (diaphragm or membrane) is placed between the electrodes. This separator must allow the free passage of ions, while acting as a barrier to keep the gases apart (see figure 2.1).

Catalysts are applied to the surface of the electrodes to increase the recombination rates of atomic hydrogen and oxygen. Without a catalytic coating, atomic hydrogen would build up on the cathode surface, hence reducing the current flow and slowing the production of hydrogen gas. The effectiveness of the catalytic coatings is improved by increasing the ratio of real to apparent surface area of an electrode. A high porosity is therefore desirable for the electrode surfaces.

In AWE, water is generally fed to the circulating electrolyte, which also provides a convenient way to remove the waste heat produced by the electrolysis reaction and control the process temperature.

2.1.2 Solid Polymer Electrolysis (SPE)

In SPE, a solid rather than liquid electrolyte is used. While acid solutions are not used today in practical water electrolysis, acid membranes offer an interesting alternative to liquid alkaline electrolytes. Acid membranes used in SPE are of the same type as those used in proton exchange membrane fuel cells (PEMFC). Their main feature is a high proton conductivity and a very low electronic conductivity. In other words, they allow the migration of protons (or more accurately hydroxonium ions – H_3O^+: a proton attached to a water molecule) between the electrodes, while preventing electrons to go through the same path. Electrons have to pass by an external circuit to go from one electrode to the other. The principles of SPE are illustrated in figure 2.2.

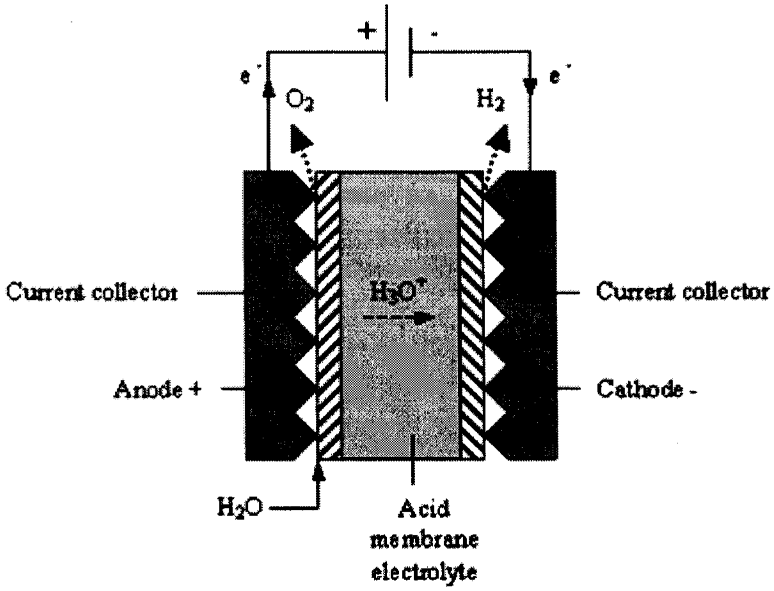


Figure 2.2: Principle of solid polymer electrolysis (SPE).

The reactions taking place at each of the electrodes in SPE are different from the reactions in AWE, but the overall water-splitting reaction is the same.

$$\text{Cathode:}\quad 2H_3O^+ + 2e^- \Rightarrow 2H_2O + H_2 \qquad (2.10)$$

$$\text{Anode:}\quad 3H_2O \Rightarrow 2H_3O^+ + 2e^- + \tfrac{1}{2}O_2 \qquad (2.11)$$

$$\text{Overall reaction:}\quad H_2O \Rightarrow H_2 + \tfrac{1}{2}O_2$$

Water is decomposed electrochemically at the anode in oxygen gas, hydroxonium ions (H_3O^+) and electrons (reaction 2.11). The hydroxonium ions then migrate through the membrane and recombine with electrons, which pass via an external circuit, to form hydrogen gas and water at the cathode (reaction 2.10).

The polymer membranes used in SPE serve both the roles of electrolyte and separator. Most membrane materials are based on "sulphonated" fluoropolymers to conduct protons. PTFE (polytetrafluoroethylene, also known commercially as Teflon®) is the fluoropolymer normally used in SPE membranes. PTFE is created by substituting fluorine for the hydrogen in a polyethylene polymer. The basic PTFE polymer is then "sulphonated", i.e. side chains are added, ending with sulphonic acid HSO_3. An example of a side chain structure attached to PTFE is shown in figure 2.3 [49]. The most well known membrane material for both SPE and PEM fuel cells is Nafion®, which has been developed by DuPont through several variants since the 1960's.

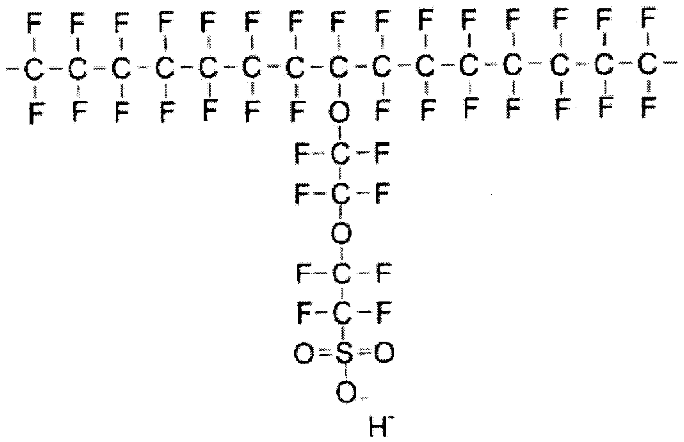


Figure 2.3: Example structure of a sulphonated fluoropolymer [49].

The HSO_3 group is ionically bonded, so the end of each side chain is actually an SO_3^- ion. The presence of SO_3^- and H^+ ions results in strong mutual attraction between the + and – ions from each side chain molecule, thus creating "clusters" of sulphonic acid within the material. A key property of sulphonic acid is that it is highly hydrophyllic – it attracts water; PTFE on the other hand is hydrophobic – it repels water. The hydrophyllic regions around the clusters can absorb relatively large amounts of water (increasing the dry weight of the membrane by up to 50%). Within these hydrated regions, the H^+ ions (protons) are relatively free to move, thus creating a dilute acid. Between the hydrated regions, it is still possible for H^+ ions to migrate short distances through the supporting long molecule structure, albeit with more difficulty. A well-hydrated membrane is therefore key to promote the flow of protons and the overall electrolysis reaction rate. Protons crossing the membrane electrolyte drag water molecules with them, which explains the appearance of hydroxonium ions (H_3O^+) in reactions 2.10 and 2.11.

Each electrode is usually made of a thin layer of carbon-supported platinum catalyst, bonded to the membrane electrolyte. Platinum is still considered to be the best catalyst for both the anode and cathode; but the amount required for SPE has been considerably reduced over the last decade (below 1 mg of platinum per cm^2 of membrane), largely due to advances in PEM fuel cell technology.

The upper temperature limit of the fluoropolymer membrane material is around 125-150 ^oC, however most SPE electrolyzers operate on liquid water at a temperature of 80 ^oC [22]. Higher operating temperatures could be achieved with new polymer membrane materials or even ceramic proton-conducting materials. At these higher temperatures, water is present as steam when it undergoes the electrolysis reaction. To remove the waste heat generated by SPE electrolysis, the feed water is generally circulated at a sufficient rate over the anode side [23].

One of the advantages of SPE is the capacity to operate at higher current density than AWE. For instance, SPE can operate at over 90% energy efficiency at a current density of 1-2 A/cm^2 [50-51]. This compares to a current density of about 0.3 A/cm^2 used in AWE to obtain a similar energy efficiency [52-53]. In other words, in spite of higher material costs, an SPE electrolyzer would require only a fraction of the cell area required in an AWE electrolyzer to produce hydrogen at the same rate and high efficiency.

Finally, the compact design of SPE electrolyzers (each cell is only a few millimeters thick) is well suited for high pressure electrolysis. SPE electrolyzers with operational pressures up to 20 MPa (3000 psi) are currently used for US Navy submarine oxygen generators [54].

2.1.3 High Temperature Electrolysis (HTE)

HTE takes place at much higher temperatures than AWE or SPE, typically in the 900-1000 °C range, and water is fed as steam. The electrolyte is made of a solid ceramic material that conducts oxygen ions. The high operating temperature is necessary for ceramics to offer a satisfactory ionic conductivity. Vapour-phase electrolysis is also desirable from a thermodynamic perspective, as it allows a greater portion of the required energy to come from heat instead of electricity (see section 2.2.1: Thermodynamics).

Just like SPE is essentially a PEM fuel cell operating in reverse, HTE relies on the same chemistry and materials as a solid oxide fuel cell (SOFC). The ceramic solid electrolyte allows oxygen ions to migrate from the cathode to the anode, while electrons have to move via an external circuit to go from the anode to the cathode. The ceramic electrolyte also acts as a gas separator. The principles of HTE are illustrated in figure 2.4.

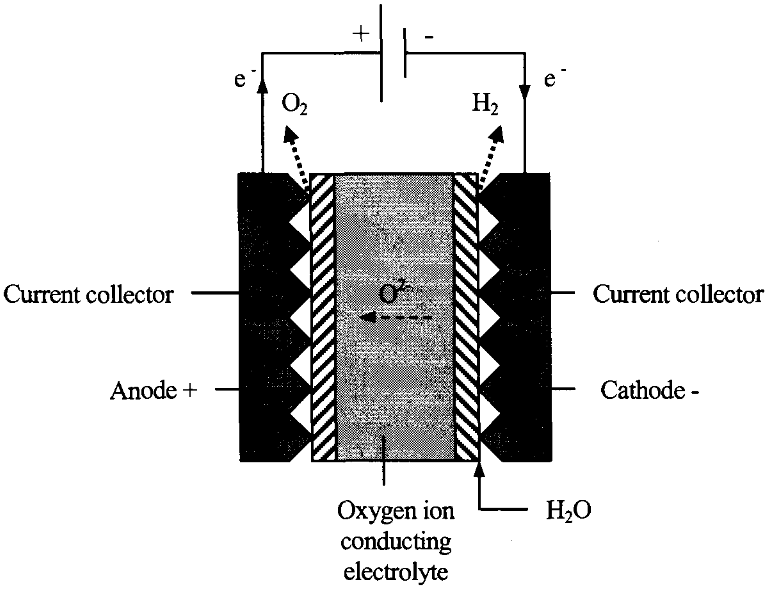


Figure 2.4: Principles of high temperature electrolysis (HTE).

Once again, the basic reactions taking place at the electrodes are different from those in AWE or SPE, but the overall water-splitting reaction remains the same.

Cathode: $$H_2O + 2e^- \Rightarrow H_2 + O^{2-} \tag{2.12}$$

Anode: $$O^{2-} \Rightarrow \tfrac{1}{2}O_2 + 2e^- \tag{2.13}$$

Overall reaction: $$H_2O \Rightarrow H_2 + \tfrac{1}{2}O_2$$

Vaporized water is fed to the cathode chamber where it reacts with electrons to be split into hydrogen and oxygen ions (reaction 2.12). After migrating to the anode, the oxygen ions then release electrons and combine in pairs to create oxygen gas (reaction 2.13).

2.1.4 Basic Electrolyzer Configurations

Industrial electrolyzers are composed of multiple electrolysis cells or electrode pairs, which may be connected in parallel or in series. There are two primary electrolyzer configurations commonly known as the tank type (or monopolar) and the filter-press type (or bipolar).

In a tank electrolyzer, each individual electrode is fed current from outside and has a single polarity (monopolar), i.e. it is either a cathode or an anode. The cells within a tank are connected in parallel as shown in figure 2.5. The voltage across the whole tank is the same as the voltage across any individual cell, E_{cell} (typically 1.5-2 Volts), irrespective of the number of electrode pairs in the tank.

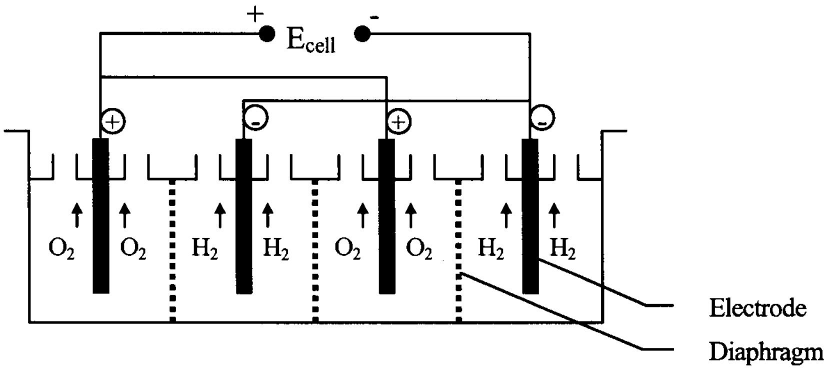


Figure 2.5: Principles of a tank electrolyzer (monopolar).

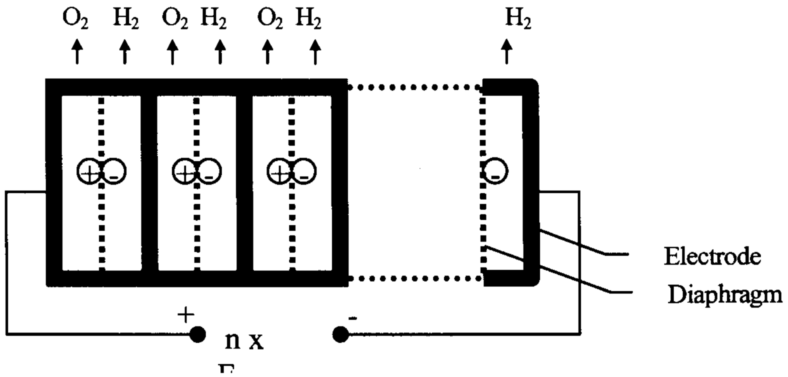


Figure 2.6: Principles of a filter-press electrolyzer (bipolar)

In a filter-press electrolyzer, each electrode is an anode on one side and a cathode on the other (bipolar electrodes), except for the two end electrodes, one of which is only an anode and the other only a cathode. The cells are connected in series and current is fed to the end electrodes as shown in figure 2.6. The voltage across the whole stack or "filter press" of "n" cells is equal to "n" times the voltage of an individual cell, E_{cell}.

There are advantages and disadvantages to each of the two configurations (see reference [23] for a detailed list). Essentially, the tank cell is simple and sturdy, it uses relatively inexpensive parts, and individual cells are easily isolated for maintenance. However, it has an inherently higher power consumption due to potential drop in cell hardware, and is contingent upon a high current to give a reasonable production. The filter-press design is more compact, generally more efficient; it can work at higher current densities and can readily operate at higher pressure and temperature, but presents more challenging design issues, similar to the ones faced by fuel cells. Tank electrolyzers were developed first, but today, nearly all commercial electrolyzers are of the filter-press type, regardless of the specific electrolysis technology used (AWE, SPE, HTE).

Rectifiers or AC/DC converters are necessary to enable electrolyzers to use alternative current (AC) from the grid. To minimize the cost and inefficiencies of this step in an electrolysis plant, tank or filter-press electrolyzers are themselves connected in various arrangements. Tank electrolyzers are typically connected in series as in figure 2.7 (a) to increase the overall voltage (about 2 Volts per tank), whereas the more flexible filter-press electrolyzers are often connected in a "parallel and series" arrangement (figure 2.7 (b)) to accommodate both the production rate and the optimal plant voltage.

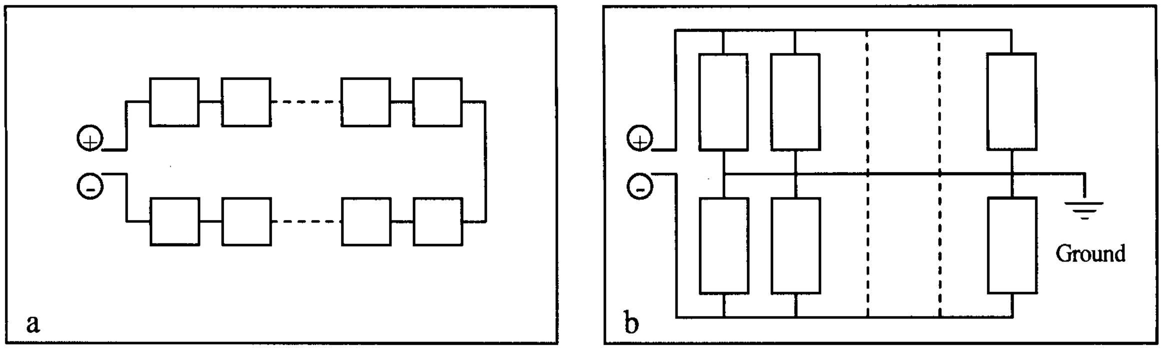


Figure 2.7: (a) Series connection and (b) "Parallel and series" connection of electrolyzers.

2.2 Energy Use

Previous techno-economic studies show that electricity is nearly always the largest component of electrolytic hydrogen cost, typically accounting for more than 50%, and as much as 80% of its cost [28,55]. It is therefore fundamental to understand the physical limitations of water electrolysis in terms of energy use, to get an appreciation of the room for potential improvements.

2.2.1 Thermodynamics

The net water-splitting reaction is, as stated before:

$$H_2O \Rightarrow H_2 + \tfrac{1}{2}O_2 \qquad (2.14)$$

Since this net reaction is the same for AWE, SPE and HTE, the thermodynamic aspects are identical for all of these water electrolysis technologies [23].

A simplified process diagram shows the material and energy flows in standard electrolysis (figure 2.8). Pure water enters the system; hydrogen and oxygen leave it. Electricity is supplied to the system; heat is removed from and/or supplied to it.

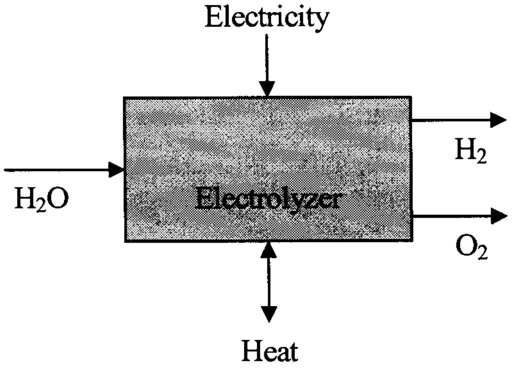


Figure 2.8: Simplified process diagram for hydrogen production by water electrolysis.

The energy change of reaction 2.14, i.e. the theoretical energy required for the reaction to proceed, can be expressed through the following thermodynamic equation:

$$\Delta H = \Delta G + T\Delta S \qquad (2.15)$$

where ΔH is the enthalpy change of the reaction, ΔG is the Gibbs free energy change, T is the absolute temperature and ΔS is the entropy change [48].

The Gibbs free energy change ΔG corresponds to the portion of the total reaction energy that must be supplied in the form of electricity, when water splitting is performed by electrolysis. The term "TΔS" corresponds to the portion of the total reaction energy that could thermodynamically be covered by thermal energy.

Under standard temperature and pressure conditions (STP[1] – indicated below by superscript ^{0}), the enthalpy change of reaction 2.14 based on liquid water is

$$\Delta H^0_{298,L} = 285.8 \text{ kJ/mol}$$

This value also corresponds to the so-called higher heating value (HHV) of hydrogen, which is the theoretical amount of energy released when pure hydrogen is combusted completely with oxygen, and water appears as a liquid in the products of combustion.

The corresponding change in Gibbs free energy at STP is

$$\Delta G^0_{298,L} = 237.2 \text{ kJ/mol}$$

In other words, 237.2 out of 285.8 kJ/mol, or 83% of the minimum energy required to electrolyze liquid water under standard conditions *must* come from electricity. The other 17% could theoretically be supplied by heat or by electricity as well.

In practice, electricity provides all of the energy theoretically required by a low-temperature electrolysis cell (e.g. 80 °C), and some more to overcome various losses. The result of these inefficiencies is waste heat that must be dissipated. However, it is possible to have heat provide part of the energy required at higher temperatures. It is even conceivable that an extremely well performing low-temperature electrolyzer could use heat from its surroundings to provide a small portion of the energy required, in which case the electrolyzer would act as a refrigerator [56]. Such an electrolyzer is highly unlikely though.

Two distinct cell voltages can be calculated from the change in Gibbs free energy ΔG and the reaction enthalpy ΔH. The first one is called the reversible voltage, E_{rev}, and is given by:

---

[1] Standard temperature and pressure or standard reference state, i.e. 25 °C (298.15 K) and 1 bar.

$$E_{rev} = \frac{\Delta G}{2F} \tag{2.16}$$

where F is the Faraday constant. It corresponds to the minimum electrical potential needed to drive the electrolysis reaction. At STP, E_{rev} has a value of 1.23 Volts.

The voltage associated with ΔH is commonly called the thermoneutral cell voltage, E_{tn}. It is the voltage at which a perfectly efficient cell would operate if electricity provided the entire energy requirement. Under these conditions, the cell does not generate any waste heat, nor does it require any heat input; the cell has no net heat exchange, hence it is then said to be "thermoneutral". At STP, E_{tn} has a value of 1.48 Volts.

$$E_{tn} = \frac{\Delta H}{2F} \tag{2.17}$$

To summarize, if an electrolysis cell operates below the reversible voltage E_{rev}, no sustained water splitting can occur. If it operates between E_{rev} and the thermoneutral voltage E_{tn}, then the process is endothermic and part of the energy required to split water comes from heat. If it operates above E_{tn}, the process is exothermic, meaning that excess heat must be dissipated, and all of the energy required comes from electricity.

ΔH and ΔG, and consequently E_{tn} and E_{rev}, are functions of the temperature, pressure and electrolyte composition.

Equations 2.16 and 2.17, which link energy and voltages, can be derived easily. As indicated in the previous section, two electrons must pass round the external circuit to split each water molecule. So, for one mole of hydrogen produced, $2N$ electrons must pass round the external circuit (where N is Avogadro's number). If $-e$ is the charge on one electron, then the charge that flows is:

$$-2Ne = -2F \text{ Coulombs}$$

F being the Faraday constant.

If E is the actual voltage of an electrolysis cell, then the electrical work done by the electrolyzer, moving this charge round the circuit is:

$$\text{Electrical work done} = \text{charge} \times \text{voltage} = -\,2F{\cdot}E \text{ Joules}$$

The work done *by* the electrolyzer is a negative value because work actually has to be done *on* the electrolyzer by the outside environment for water electrolysis to take place. If the system is reversible, then the electrical work done by the electrolyzer will be equal, but of opposite sign, to the change in Gibbs free energy ΔG resulting from the electrolysis reaction. Thus

$$-2F\cdot E = -\Delta G$$

Which brings us back to equation 2.16

$$E_{rev} = \frac{\Delta G}{2F}$$

A similar procedure leads to equation 2.17 [49].

Figure 2.9 shows the thermoneutral (E_{tn}) and reversible (E_{rev}) voltages, as a function of temperature, for a standard pressure of 1 bar. The portion of energy that could be covered by heat, TΔS, can also be translated into a voltage (TΔS/2*F*); this curve appears at the bottom of figure 2.9. Consistent with equation 2.15, the sum of the reversible voltage and the voltage associated with the heat portion is equal to the thermoneutral voltage.

$$\frac{\Delta H}{2F} = \frac{\Delta G}{2F} + \frac{T\Delta S}{2F} \tag{2.18}$$

The brake of the curves at 100 °C is due to the transition from liquid water to steam. It corresponds to the evaporation energy of water.

The value of the thermoneutral voltage in figure 2.9 is given for any electrolysis temperature *T* in the range 25-1000 °C. However, it does not take into account the energy required to heat (and evaporate) the feed-water from 25 °C to temperature *T*. This additional amount of energy is accounted for in the so-called higher-heating-value voltage, E_{HHV}, which is defined as [23]:

$$E_{HHV} = \frac{\Delta H_T}{2F} + \frac{1}{2F}\int_{298}^{T} \overline{C}_p(H_2O)dT \tag{2.19}$$

where $\overline{C}_{p(H_2O)}$ refers to the heat capacity of water. E_{HHV} appears as the top-most curve on figure 2.9.

As illustrated in figure 2.9, the reversible voltage E_{rev} decreases significantly from 1.23 Volts at 25 °C (298 K) to 0.92 Volt at 1000 °C (1273 K). It means the amount of electrical energy needed to perform electrolysis is reduced at higher operational temperatures. The thermoneutral voltage E_{tn} remains relatively constant though (except for the drop associated with water vaporization), while the higher-heating-value voltage E_{HHV} grows steadily from 1.48 Volts at 25 °C to 1.72 Volts at 1000 °C.

In other words, although the energy required to electrolyze water as such is relatively constant, as indicated by the thermoneutral voltage, the portion that has to be supplied by electricity decreases as a function of temperature, as indicated by the reversible voltage. In fact, the electricity requirement decreases by 25% (from 1.23 V to 0.92 V) between 25 °C and 1000 °C. On the other hand, the higher-heating-value voltage clearly increases with temperature as a result of the greater energy needed to bring the feed water to the operating temperature.

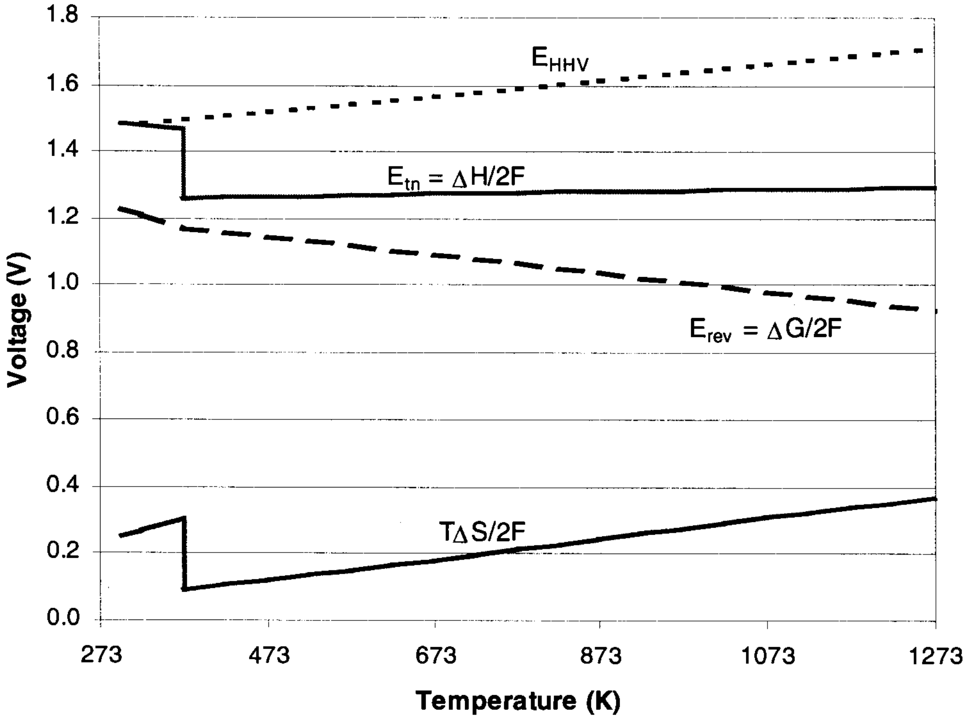


Figure 2.9: Theoretical water electrolysis voltages as a function of temperature.

Appendix A gives more detailed information on the thermodynamics of water electrolysis and the data used to generate the graph of figure 2.9.

2.2.2 Efficiencies

There is some confusion in the literature about the various efficiencies of water electrolysis. Different authors talk about efficiency, energy efficiency, electrical efficiency, current efficiency, electrochemical efficiency, exergy efficiency [22, 48, 50, 56, 57, 58]; sometimes at the cell level, and sometimes at the electrolyzer system level (including AC/DC conversion, etc.).

Probably the most general definition of the energy efficiency of the electrolysis process is given as [58]:

$$\textit{Energy efficiency} = \frac{\textit{Energy output in products}}{\textit{Total energy input}}$$

In the case of conventional water electrolysis, the energy input is limited to electrical energy. Hence, the energy efficiency of an electrolyzer has traditionally been defined as "the energy that ideally could be recovered by reoxidation of the hydrogen and oxygen coproducts to water (the heating value of hydrogen), divided by the energy supplied to the electrolysis system in electrical form" [57].

$$\textit{Energy efficiency} = \frac{\textit{Heating value of hydrogen output}}{\textit{Energy of electrical input}} \tag{2.20}$$

Some references use the lower heating value (LHV) of hydrogen while others use its higher heating value (HHV) to calculate the energy efficiency of electrolysis. In this research, the HHV value is always the one used, as it better reflects the full energy content of hydrogen.

Because this last definition disregards thermal energy inputs, the energy efficiency could reach values above 100%. For instance, in the case where an electrolyzer operates below the thermoneutral voltage, some heat from the surroundings is used as an energy input, without being considered in the definition above.

At the cell level, when electricity is the only energy source, the energy efficiency of the electrolysis process could be defined as the ratio of the thermoneutral voltage (for liquid water at STP – 1.48 Volts – $E_{tn,\ 298,\ L}$) to the actual cell voltage (E) [22], multiplied by the current efficiency [50].

$$Energy\ efficiency = \frac{E_{tn,298,L}}{E} \times Current\ efficiency \qquad (2.21)$$

The current efficiency is simply the ratio of the number of electrons theoretically required to produce a given amount of hydrogen over the actual number of electrons supplied by the electrical current in producing this amount of hydrogen (equation 2.22). As mentioned earlier, two electrons are required for each molecule of hydrogen produced.

$$Current\ efficiency = \frac{Volume\ of\ generated\ H_2\ (Nm^3/h) \times 96{,}487\ (C/mol\ e^-) \times 2(mol\ e^-/mol\ H_2)}{Current\ (A) \times 3{,}600\ (s/h) \times 0.0224\ (Nm^3/mol\ H_2)} \qquad (2.22)$$

Current efficiency is typically around 99%, whereas the energy efficiency as defined in equation 2.21 varies more widely in the 75-95% range, depending on the particular electrolysis technology and operating conditions. The 75-95% range is also representative of actual energy efficiency values according to the definition of equation 2.20, based on the HHV value of the hydrogen produced. The corresponding range when the LHV value of hydrogen is used is 63-80%.

These relatively high efficiency values are based on electricity as the energy source. However, if we consider electricity as an energy currency derived from another energy source (e.g. coal, natural gas, etc.) the overall efficiency of hydrogen production by electrolysis can drop dramatically, down to the 30% range. Rosen and Scott have proposed a simple methodology to evaluate the energy and exergy efficiency of water electrolysis in a way that allows straightforward and relevant comparison with other hydrogen production processes [58, 59, 60].

The particular efficiencies used for the cost model are defined and explained in Chapter 3.

2.2.3 Cell Voltage

The power consumption of an electrolysis cell is directly proportional to the cell voltage and inversely proportional to its current efficiency. Since current efficiency is usually very close to 100%, the parameter of importance in evaluating water electrolysis cells design is the magnitude of the cell voltage.

Water electrolysis under actual conditions demands a cell voltage E that is substantially higher than the reversible value E_{rev}. It has to overcome the electrical resistance in the electrodes, in the electrolyte between the electrodes, and in the separator. Additionally, it has to cover the so-called overpotentials at the electrodes, which are kinetically determined. The cell voltage can then be expressed as [22]:

$$E = E_{rev} + \eta_c + \eta_a + jR^* \tag{2.23}$$

where η_c is the cathodic overpotential (hydrogen overvoltage), η_a is the anodic overpotential (oxygen overpotential), j is the current density and R^* is the sum of the electrical resistances, based upon the active electrode area.

Figure 2.10 shows an example of the relations between voltages and current density in conventional alkaline electrolysis. The cell voltage increases with current density, the ohmic resistance portion following a linear progression. An example of actual values is given in table 2.1, referring to an industrial electrolyzer using alkaline electrolyte at common conditions (25% KOH electrolyte, 80 °C, 1 bar) [22].

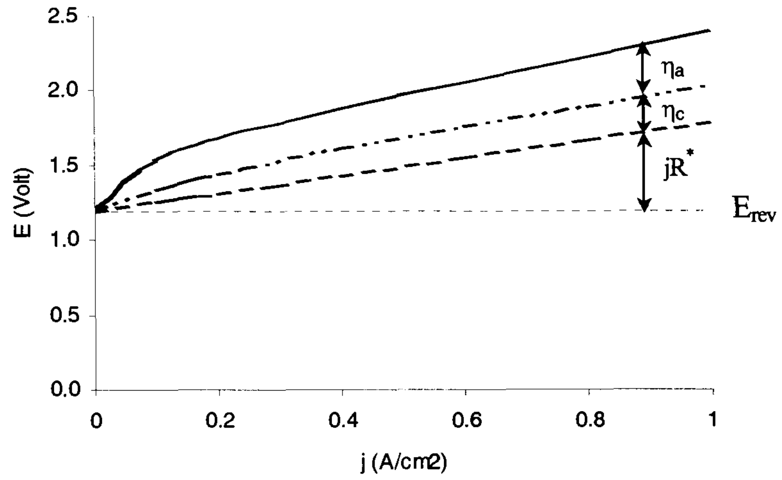


Figure 2.10: Voltage vs. current density relationships.

Ohmic resistances		$\Omega\ cm^2$
Electrodes	$R^*_a + R^*_c$	$2.0 \cdot 10^{-2}$
Electrode surfaces	$R^*_{as} + R^*_{cs}$	$31.2 \cdot 10^{-2}$
Electrolyte	R^*_e	$41.4 \cdot 10^{-2}$
Separator	R^*_s	$36.0 \cdot 10^{-2}$
Sum	R^*	$110.6 \cdot 10^{-2}$

Voltages		V
Reversible cell voltage	E_{rev}	1.189
Electrode overpotentials (at $j = 0.2$ A/cm^2)	$\eta_c + \eta_a$	0.325
Ohmic voltage (at $j = 0.2$ A/cm^2)	jR^*	0.221
Sum		1.735

Table 2.1: Example of ohmic resistances and cell voltage elements.

The electrical resistance in the electrodes is determined by the material and design of the electrodes and the temperature. The resistance in the interface electrode/electrolyte is function for one thing of the wetting conditions, i.e. how much of the electrode surfaces are in direct contact with the electrolyte (gas bubbles on the electrode surfaces increase this resistance). The resistance in the electrolyte is determined by the resistivity of the electrolyte (function of composition and temperature) and the gap between the electrodes. The resistance in the separator is dependent on its material composition and structure.

The overpotentials are determined by the activity of the electrode surfaces, the electrolyte composition and temperature. Most standard electrochemistry textbooks discuss the fundamentals of electrode kinetics for water electrolysis, including theoretical calculations for the hydrogen and oxygen overvoltages, based on the Tafel equation [23]. One important point to note is that, similarly to fuel cells, the electrode kinetics of the oxygen side is more complex and often more limiting than the hydrogen side.

Finally, the ohmic resistance related to the flow of electrons through current-collecting structures (not accounted for in the table above) is relatively unimportant in the bipolar design, though it is not negligible in unipolar electrolyzers.

2.2.4 Effect of Operating Conditions

2.2.4.1 Temperature

As illustrated in figure 2.9, increasing the electrolysis temperature reduces the reversible voltage E_{rev}, and therefore the minimum electrical energy input. Quantitatively, it shows that there is a potential for reducing the minimum electrical input by about 25%, when temperature is increased from 25 °C to 1000 °C.

Yet, the overall theoretical amount of energy required to perform electrolysis at high temperature is not lower, but rather slightly higher as indicated by the higher-heating-value voltage E_{HHV} in figure 2.9.

What higher temperature electrolysis has to offer then is more flexibility to use heat as an energy input, and increased efficiency due to improved kinetics. When available, heat is generally cheaper than electricity, and sometimes even free if the electrolyzer is located near an existing heat source (e.g. nuclear reactor).

2.2.4.2 Pressure

The electrolysis pressure also has an effect on the energy requirement for producing electrolytic hydrogen. The reversible voltage for a given temperature T and pressure P ($E_{rev,T,P}$) can be calculated from the Nernst equation as:

$$E_{rev,T,P} = E_{rev,T,P=1} + \frac{RT}{nF}\ln\frac{a_{H_2}(a_{O_2})^{1/2}}{a_{H_2O}} \tag{2.24}$$

where R denotes the universal gas constant, n the number of electrons to split each water molecule ($n = 2$), F the Faraday constant, and a the activity of a species [23]. $E_{rev,T,P=1}$ is the reversible voltage at temperature T (in Kelvin) and standard pressure $P = 1$ bar. Its value is given by the curve E_{rev} on figure 2.9. The exponent of each activity a corresponds to the species coefficient in the water splitting reaction (reaction 2.14).

The activities of hydrogen (a_{H_2}) and oxygen (a_{O_2}) can be approximated by their respective pressure ratio to atmospheric pressure (P_{H2}/P_o) and (P_{O2}/P_o). Because during electrolysis the pressure is normally the same on the oxygen side and the hydrogen side, we can assume that

$P_{H2} = P_{O2} = P$. The numerator of activities in equation 2.24 then becomes simply $(P/P_o)^{3/2}$. The activity of water (a_{H_2O}) can be approximated as 1. Assuming P_o = 1 bar, equation 2.24 becomes:

$$E_{rev,T,P} = E_{rev,T,P=1} + \frac{3RT}{4F} \ln P \qquad (2.25)$$

with P expressed in bar.

A more comprehensive explanation is given in reference [23]. An alternative approach based on thermodynamics and the perfect gas law also leads to the same result.

At T = 298 K, equation 2.25 predicts a voltage increase of about 44 mV at 10 bar (~ 150 psi), 88 mV at 100 bar (~ 1500 psi) and 115 mV at 400 bar (~ 6000 psi). For example, an electrolyzer operating with 10 bar output at 1.55 V might need only 1.62 V to operate at 400 bar, based on theoretical considerations. (1.55 V + (115 mV – 44 mV) = 1.62 V)

Although high pressure increases the theoretical reversible voltage by a few percents, it can generally be justified in actual electrolyzers by the energy saving due to increased efficiency (reduced operating voltage) and higher achievable current density [56]. For instance, one effect of high pressure is to reduce the size of gas bubbles on the electrode surfaces, hence improving the cell performance [23]. So there seems to be an optimum pressure level (which varies with the particular electrolysis technology used) for which the advantages outweigh the slight increase in the theoretical voltage.

Now, the principal interest in high-pressure operation is to save the cost of compressing hydrogen after it is produced [61]. Assuming that gaseous hydrogen is stored onboard FCVs at high pressure, say 350 bar (~ 5000 psi), a compressor must bring it to an even higher pressure at the fuelling station, say 400 bar (~ 6000 psi). Equation 2.25 indicates that in theory, the electrolyzer itself could provide the high pressure with a relatively small penalty on energy use. The small drop in energy efficiency might then justify the elimination of the compressor from the refueling system. However, very high pressures up to 400 bar would most likely place severe mechanical constraints on the electrolyzer [43] and increase its capital cost.

So the electrolyzer pressure must be selected also taking into account the compression strategy. There are trade-offs in the cost and complexity of the electrolyzer and compressor. There may be some merit to providing a moderately high electrolyzer output pressure, say 100 bar (~ 1500 psi), to reduce the burden on the compressor. A simpler single-stage compressor (instead of multi-stage) could then boost the pressure from 100 to 400 bar.

Figure 2.11 shows the relative energy use of a perfectly efficient electrolyzer and a single-stage compressor working at 75% efficiency (adiabatic compression) to achieve a storage pressure of 400 bar (6000 psi). It shows that most of the theoretical energy necessary to compress hydrogen is spent in the initial part of compression. For instance, in bringing the pressure from 1 to 400 bar, 60% of the theoretical energy of adiabatic compression is spent in bringing hydrogen pressure to 10 bar (~ 150 psi), and 90 % to 100 bar (~1500 psi).

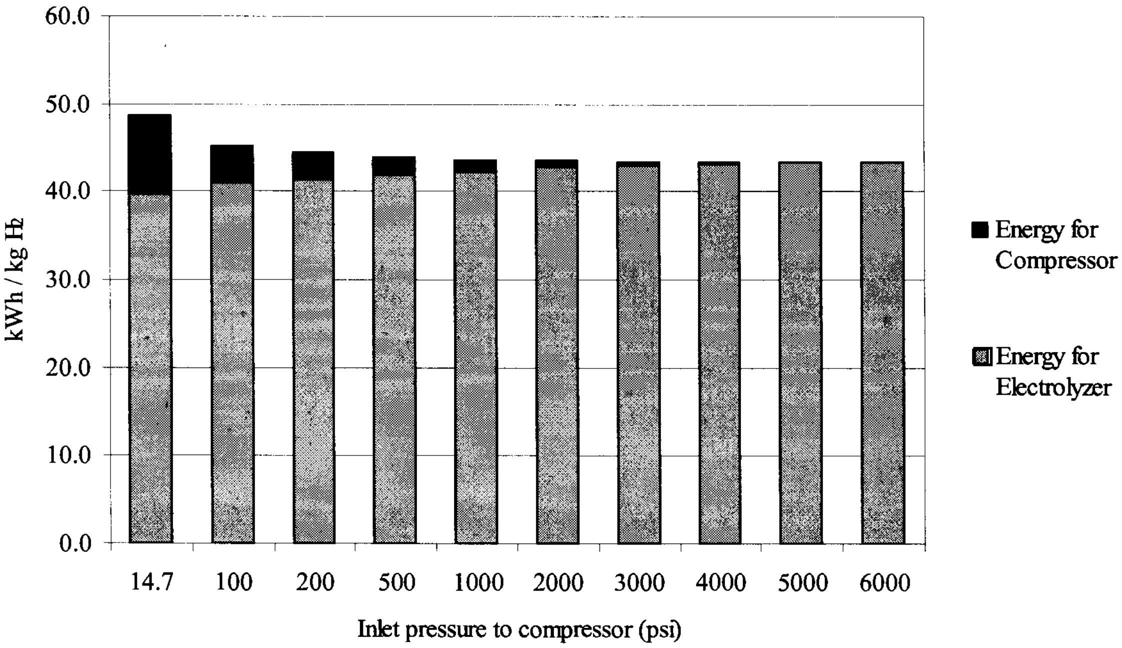


Figure 2.11: Ideal electrolyzer/compressor energy use per kilogram of hydrogen. Electrolyzer efficiency = 100% at 80 °C, compressor efficiency = 75% single-stage adiabatic compression.

2.2.4.3 Current density

As pointed out earlier, the specific energy use of a water electrolysis cell is proportional to its operating voltage. In return, the voltage is directly affected by the operating current density. The resistance inside an electrolytic cell goes up with an increase in current density, and so does the operating voltage. Hence, the operating voltage and specific energy use of an electrolysis cell are, to some extent, proportional to its operating current density.

The rate at which the operating voltage increases as a function of operating current density depends on the particular electrolysis technology and cell design considered. For example, the operating voltage in conventional AWE increases much more steeply with current density than it does in SPE. That explains why conventional AWE operates at a fraction of the current density used in SPE (typically 0.2-0.5 A/cm^2 for AWE vs. 1-3 A/cm^2 for SPE). Therefore, even though AWE requires less expensive cell materials, it needs about 3 to 5 times more electrode surface area than SPE, as shown in figure 2.12. See references [51-52] respectively for specific characterization of SPE and AWE current density vs. voltage relationships.

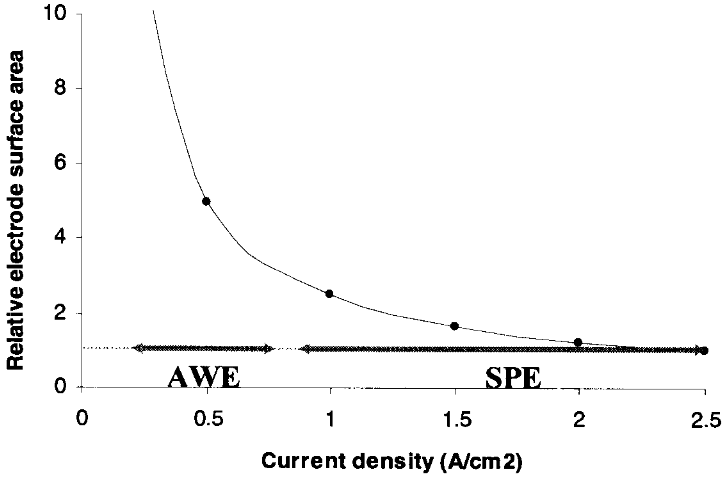


Figure 2.12: Relative electrode surface area as a function of current density.

For each design and application, there is an optimum current density that minimizes the overall cost of hydrogen. This is shown clearly in a sensitivity analysis for SPE performed within the Japanese WE-NET program [51], where they found the most cost-effective current density to be in the range of 2-2.5 A/cm^2.

Because the effect of current density varies widely between various electrolysis technologies, it has not been included as a variable in the cost model developed for this thesis. Instead, the nominal rated operating current density is assumed in the specific capital cost of an electrolyzer. However, other studies focusing on a single electrolysis technology (e.g.

conventional AWE) have included the effect of operating current density (in relation to rated current density) on the cost of electrolytic hydrogen [34].

2.2.5 Overall Energy Use of an Electrolyzer Cell

The specific energy use of an electrolyzer can be estimated in a straightforward manner from its single-cell operating voltage (E) and current efficiency (η_i).

Regardless of the operating conditions, the number of electrons (e^-) required to obtain one kilogram of hydrogen from water electrolysis is a fixed quantity: 26.589 kAh (kiloAmpere-hour). It comes from the fact that two electrons ($n = 2$) are needed to generate each molecule of hydrogen from water. The rest is simply a conversion of units taking into account the molar mass of hydrogen.

$$\frac{2\,e^-}{H_2} * \frac{1000\,g\,H_2}{2.016\,g\,H_2\,/mol\,H_2} * \frac{96{,}487\,C}{mol\,e^-} * \frac{1\,kA}{1000\,C/s} * \frac{1h}{3600\,s} = 26.589\,kAh$$

The specific energy use of the electrolyzer K, in kWh/kg H_2, can then be approximated by the following formula:

$$K = 26.589 \times \frac{E}{\eta_i} \qquad (2.26)$$

where E is the average single-cell operating voltage (in Volts) and η_i the current efficiency. This equation does not consider the energy required to compress hydrogen to a pressure higher than the output pressure from the electrolyzer. Neither does it include the small amount of energy needed to deionize water or to convert AC to DC current for practical use by the electrolyzer. However, equation 2.26 gives a good approximation of the energy use for the electrolyzer itself.

Table 2.2 below summarizes the specific theoretical energy use of an electrolyzer cell at various temperature and pressure conditions, assuming perfect current efficiency. Table 2.3 gives corresponding values for typical commercial electrolyzer cells.

Pressure	Temperature	Single-Cell Voltage	Theoretical Energy Use	
(bar)	(°C)	(Volt)	kWh/Nm^3 H_2	kWh/kg H_2
P = 1	T = 25	E_{rev} = 1.229	2.94	32.7
		E_{tn} = 1.481	3.54	39.4
		E_{HHV} = 1.481	3.54	39.4
P = 1	T = 1000	E_{rev} = 0.922	2.20	24.5
		E_{tn} = 1.292	3.02	34.4
		E_{HHV} = 1.714	4.10	45.6
P = 400	T = 25	E_{rev} = 1.344	3.21	35.7
		E_{tn} = 1.596	3.81	42.4
		E_{HHV} = 1.596	3.81	42.4

Table 2.2: Theoretical energy use of water electrolysis as a function of pressure and temperature, based on reversible voltage E_{rev}, thermoneutral voltage E_{tn}, and higher-heating-value voltage E_{HHV} (assuming current efficiency of 100%).

Pressure	Temperature	Single-Cell Voltage	Electrolyzer Cell Energy Use	
(bar)	(°C)	(Volt)	kWh/Nm^3 H_2	kWh/kg H_2
1-30	70 - 120	1.6 – 2.0	4.0 – 5.0	45 - 55

Table 2.3: Typical operating conditions and energy use of commercial electrolyzers.

2.3 Trends in Water Electrolysis Technologies

Broadly speaking, three general trends in technology development can be observed to reduce the cost of electrolytic hydrogen. One is to find strategies for reducing the energy use; another is to reduce the capital cost of electrolyzer systems; and a more recent one is to take advantage of technical advances in fuel cell technology, which shares many similarities with water electrolysis.

2.3.1 Decrease Energy Use

As explained earlier, the energy use is directly proportional to the operating voltage. One way to keep this voltage as low as possible is to lower the electrical resistance in the electrolyzer hardware; namely by reducing the gap between electrodes to a minimum. Advanced technologies use a "zero-gap" sandwich-type configuration, in which porous electrodes are pressed on the opposite faces of the separator/membrane, and the gases evolve predominantly on the backsides of the electrodes. Variations of this principle are applied to AWE, SPE and HTE to reduce the electrical resistance [61].

Another approach is proposed to minimize the increased electrical resistance due to the collection of bubbles at the electrodes at high current density. It consists of subjecting the electrolysis cell to a centrifugal force to promote the mass transport within the cell and the separation of gas bubbles from the electrodes, electrolyte and membrane. Experimental work to test the validity of this approach was carried out by Cheng et al. on AWE cells in centrifugal fields of up to 190 G [62]. The results were conclusive in showing a net reduction in energy use for a given current density.

High temperature electrolysis is another way to decrease the cost of energy by substituting inexpensive heat instead of electricity. The German "HOT ELLY" electrolyzer developed at the end of the 1980's and thin film electrolyzer cells developed at the Lawrence Livermore National Laboratory (LLNL) are good examples of HTE [63]. HTE typically exhibits high energy and current efficiencies compared to conventional AWE.

A more recent approach to cut drastically the operating voltage has been proposed and demonstrated at LLNL. The principle is to supply natural gas on the anode side to reduce the chemical potential difference across the electrolyzer, thus minimizing the electrical consumption. The technique is an extension of HTE, taking place at 900 °C, and is called natural gas assisted steam electrolysis (NGASE) [63]. Here, the oxygen produced from water electrolysis is used to partially oxidize natural gas to CO and hydrogen (reactions 2.27 and 2.28). CO can be subsequently shifted to yield extra hydrogen (reaction 2.29). The electrolysis voltage is then reduced close to zero since most of the energy comes from natural gas (see figure 2.13).

With NGASE, when all the energy comes from natural gas instead of electricity, the overall reaction is equivalent to the steam reforming of natural gas.

Cathode: $$H_2O + 2e^- \Rightarrow H_2 + O^{2-} \tag{2.27}$$

Anode: $$CH_4 + O^{2-} \Rightarrow CO + 2H_2 + 2e^- \tag{2.28}$$

Shift Reaction: $$CO + H_2O \Rightarrow H_2 + CO_2 \tag{2.29}$$

Overall reaction: $$CH_4 + 2H_2O \Rightarrow 4H_2 + CO_2$$

In this case, the main advantage of NGASE is essentially a compact modular design for the production of hydrogen from natural gas and water.

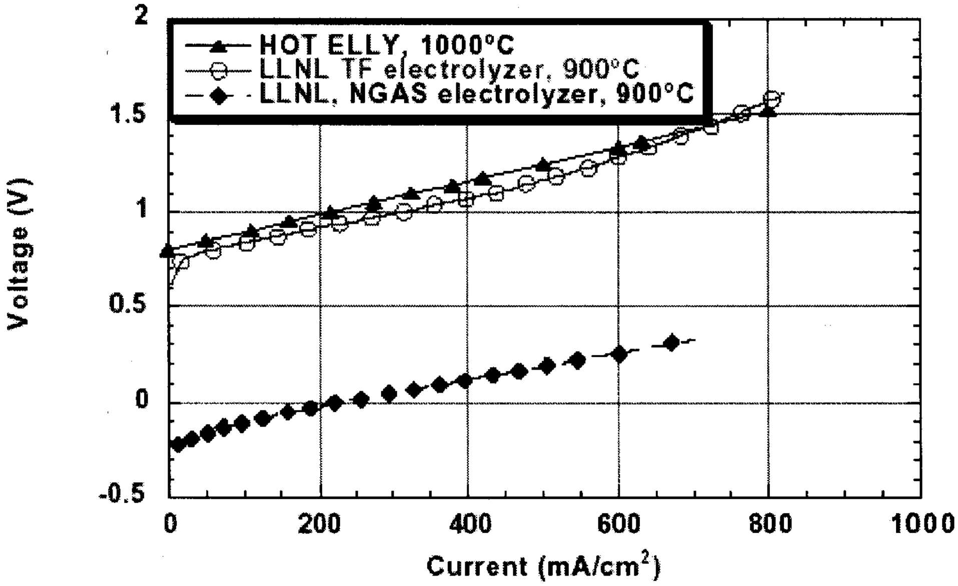


Figure 2.13: Current-voltage plots of conventional HTE and NGASE. Cathode inlet gas: H_2 (3%) + H_2O (70%) + N_2 (balance). Anode inlet gas: CH_4 (97%) + H_2O (3%). [63]

High-pressure electrolysis could also help reduce the energy use, but only to a limited extent as suggested by figure 2.11. The net result on energy use is arguable, as several effects are compounded. For instance, high-pressure electrolysis decreases the ohmic resistance in the electrolytic cells and allows a more energy efficient isothermal compression of hydrogen; on the other hand, larger parasitic currents are to be expected as a result of the reduced ohmic resistance and thus lower current efficiency [54, 64].

2.3.2 Reduce Capital Cost

Capital cost reductions can be achieved through clever engineering, cheaper materials or economies of scale from mass production. Leaving aside the impact of mass production, the main issues being worked on to reduce the capital cost of electrolyzers are summarized below.

For AWE technology:

- Development of an alternative separator suitable for high-temperature operation to replace the asbestos-based material used in conventional technology.
- Development of inexpensive, more active and stable electrocatalysts.
- Development of inexpensive construction and sealant materials resistant to alkaline corrosion, particularly at higher temperature.

For SPE technology:

- Reduction of platinum catalyst loading and development of non-noble metal catalysts.
- Development of inexpensive electrolyte membrane materials, with adequate durability and resistance to higher temperature and pressure.
- Development of suitable fabrication techniques for the commercial production of membrane electrode assemblies (MEA) and flow-field plates (current collectors).

For HTE technology:

- Development of inexpensive ceramic electrolyte and catalyst systems.
- Design optimization and scale-up.
- Development of suitable fabrication techniques.

For all technologies:

- Increase the operating current density as much as possible to reduce the size and capital cost of the electrolyzer (at a reasonable cost in efficiency losses).
- Optimization of the integrated system including the electrolyzer and all the ancillary equipment, such as heat exchangers, water deionization and gas purifiers.
- Simplification and reduction of the number of components required for an electrolyzer plant.

2.3.3 Synergy with Fuel Cell Developments

Because a water electrolyzer is essentially a fuel cell operating in reverse, water electrolysis technology could benefit directly from advances in fuel cells. That is particularly true of SPE and HTE, two promising electrolysis technologies that could take advantage of developments in their fuel cell counterparts, respectively PEMFC and SOFC, given that the vast majority of R&D efforts and investments in fuel cells are concentrated in these two types of fuel cells. For example, the U.S. DOE in collaboration with industry partners launched in 2001 a US$500 million programme to achieve "ultra-low-cost" SOFC with a cost goal of $\$400/\mathrm{kW_e}$ within 10 years [65].

Fuel cell technology could help water electrolysis on the technical front (improved design, inexpensive materials, increased efficiency) as much as on the economic one (adapted fabrication techniques, mass production).

Some innovative designs are exploiting the synergy between fuel cells and electrolyzers to integrate both functions. Regenerative fuel cell (RFC) systems are integrated systems that can produce power and regenerate their reactants using stacks of electrochemical cells. RFC systems may have separate stacks to fulfill the role of fuel cell and electrolyzer, or a single stack may perform both functions, in which case it is called a unitized regenerative fuel cell (URFC) [66]. A team of researchers working on URFC systems (based on PEM technology) at Lawrence Livermore National Laboratory (LLNL) highlights the fact that their reversibility allows them to provide their own fuel, wherever electricity is available [54]. Another example of RFC development is a low cost, high-efficiency system based on high-temperature SOFC technology [67].

2.4 Summary of Electrolysis Technologies and Main Players

This section identifies some of the main players active today in the water electrolysis market, and presents a summary table of the characteristics of the three main types of water electrolysis technology discussed in this chapter: AWE, SPE and HTE.

Stuart Energy Systems (formerly the Electrolyser Corporation) is a Canadian company with over 50 years of experience in AWE. The company has delivered thousands of installations around the globe and has provided electrolyzer fuelling stations for demonstration projects of hydrogen-fuelled FCVs, namely for fuel cell bus demonstrations in Vancouver and in California. Stuart has developed a proprietary double electrolysis plate (DEP) technology that increases the efficiency of the electrolysis equipment while lowering the capital cost. The company became public in 2000 after raising CAN$150 million. In addition to the existing industrial gas market and eventual hydrogen fuelling market, a major portion of revenues for the company is expected to come from backup power applications. The company plans the delivery of up to CAN$600 million worth of hydrogen-powered backup power units by 2008 to a single Asian client company. In 2003, Stuart acquired one of its competitors, Vandenborre Technologies, which had developed the inorganic membrane electrolysis (IME) technology [68].

In Europe, Norsk Hydro Electrolysers offers a range of electrolyzers based on AWE technology, from atmospheric to high-pressure electrolyzers (15 bar), as well as hydrogen fuelling stations. Norsk Hydro provided several hydrogen fuelling stations in Europe, namely for fuel cell buses in Iceland [7]. MTU in Germany is also active in AWE and has developed a high-pressure electrolyzer (30 bar in a pressurized container) together with Norsk Hydro [69]. Forschungszentrum Jülich, a German institute, has pursued the same approach pushing the operating pressure up to 120 bar [64].

In SPE technology, Hamilton Sundstrand – a business unit of United Technologies Company (UTC) – has been designing and manufacturing SPE electrolyzers for over 40 years. The technology was first developed for space applications. Some SPE electrolyzers operating at pressures of up to 3,000 psi (200 bar) have been qualified for use on board U.S. submarines. With over 40 million hours of system operation, the maturity of their SPE technology is well established. In 2002, the company entered into an alliance with Stuart Energy Systems to jointly develop and market integrated hydrogen generation products (based on Hamilton Sundstrand SPE technology) for vehicles, power generation and industrial uses [70].

Other companies involved in the development and commercialization of SPE electrolyzers include Proton Energy Systems in the United States [71], Hydrogenics in Canada [72] and Fuji Electric in Japan [50]. Proton Energy Systems and Hydrogenics are developing electrolyzer products specifically targeting the hydrogen fuelling application. Hydrogenics stresses that the modular and compact design of their fuelling stations allows them to be scaled for increased hydrogen generation and storage requirements.

Finally, Lawrence Livermore National Laboratory (LLNL) [63] and the small company Technology Management Inc., both in the United States, are among the few working on HTE technology.

Table 2.4 summarizes the characteristics and performance of the three main types of water electrolysis technology discussed in this chapter: AWE, SPE and HTE. This table is adapted from a paper published by Dutta [61], but some values were updated to reflect more recent information available.

	AWE			SPE	HTE
Technology	Conventional alkaline electrolyser	Advanced alkaline electrolyser	Inorganic membrane alkaline electrolyser	Solid polymer electrolyser	High temperature (water vapor) electrolyser
Development stage	Commercial large scale units	Prototypes and commercial units	Commercial units	Prototypes and commercial units	Laboratory-scale and prototype units
Cell voltage, V	1.8-2.2	1.5-2.5	1.6-1.9	1.4-2.0	0.95-1.3
Current density, A cm^{-2}	0.13-0.25	0.20-2.0	0.2-1.0	1.0-4.0	0.3-1.0
Temperature, °C	70-90	80-145	90-120	80-150	900-1000
Pressure	Ambient 1-2 atm	Up to 120 atm	Up to 40 atm	Up to 400 atm	Up to 30 atm
Cathode	Steel, stainless steel or nickel	Catalytically or non catalytically activated Ni	NiS	Carbon fiber paper & a layer of Pt catalyst	Ni
Anode	Nickel	Catalytically or non catalytically activated Ni	Spinel oxide based on Co	Porous titanium with a layer of a proprietary catalyst	Ni-NiO or Perovskite ($LaNiO_3$, $LaMnO_3$, etc)
Gas separator	Asbestos 1.2-1.7 Ω cm-2	Asbestos-based below 100°C; Teflon-bonded polybenzimidazole (PBI) K-titanate above 100°C 0.5-0.7 Ω cm^{-2}	Patented polyantimonic acid (PAM) membrane 0.2-0.3 Ω cm^{-2}	Multilayer expanded metal screens	None
Electrolyte	25-35% KOH	25-40% KOH	14-15% KOH	(Perfluorosulfonic acid) membrane 10-12 mils thick 0.46 Ω cm^{-2}	Solid Y_2O_3-stabilized ZrO_{380}
Cell efficiency	77-80%	80-90%	85-95%	85-98%	90-100%
Power consumption kWh(Nm^{3}H$_2$)$^{-1}$	4.3-4.9	3.8-4.3	3.6-4.0	3.6-4.0	2.5-3.5
Players	Stuart Norsk Hydro	Stuart Jülich Norsk Hydro Teledyne	Stuart & Vandenborre Technologies	Stuart & Hamilton Sunstrand Proton Energy Hydrogenics Fuji	LLNL Technology Management Inc. (TMI)

Table 2.4: Present and advanced electrolyser technologies at a glance.

Chapter 3 – Cost Model

3.1 General Considerations

In line with the objectives of this research, an original cost model was developed to integrate and investigate the technical, economic and comparative aspects of decentralized electrolysis. This model builds on previous studies and includes a monetary valuation of GHG emissions, site-specific information, and a more detailed account of the theoretical energy requirements. Considering that the model's main challenge lies more in the number of variables to be connected than the mathematical complexity of its equations, the software MS Excel 2000 was deemed to be an appropriate platform, and selected on the basis of its simplicity and wide use.

Previous similar cost models for electrolytic hydrogen have inspired the structure of the core aspects. The primary reference source used is a 1995 report written by Thomas and Kuhn (DTI) for the National Renewable Energy Laboratory (NREL), a national laboratory of the U.S. Department of Energy (DOE) [43]. Other significant references used are a report from The Electrolyser Corporation (now Stuart Energy Systems) prepared for the Ford Motor Company [42], as well as published work by J. M. Ogden (Princeton University) [29, 40] and Dutta et al. (Florida Solar Energy Centre) [55]. For the portion dealing with GHG emissions, the results from a 2000 report by the Pembina Institute [5] and a paper by Dones et al. (Paul Scherrer Institute) [73] constitute the principal sources. Additional references used to support these sources are other published work by Thomas et al. [4] and a study done by the International Atomic Energy Agency (IAEA) [74].

In developing the model, more emphasis was placed on ensuring proper sensitivity to the various input parameters than selecting the most representative values for the base case. Nevertheless, in order to preserve the desired level of flexibility, some actual couplings between variables are not reflected in the model. For instance, the specific capital cost of the electrolyzer ($\$/kW_e$), which is an input parameter in the present model, would be affected in reality by the operating current density, the resulting energy efficiency and the number of electrolyzers manufactured, couplings that are not explicitly defined in the model. The empirical relationships between these variables vary depending on the technology used and the sources consulted. Therefore, special care in reviewing the assumptions should be exercised before entering a given set of input values, and equal caution should be use used in interpreting the results.

3.2 Description of the Model

The cost model developed has one primary output variable: the unit cost of electrolytic hydrogen delivered to the consumer, U, in US$ per kilogram. This variable is used to study the economics of electrolytic hydrogen for FCVs from both an "absolute" and a "comparative" standpoint. The former is concerned with the sensitivity of U itself to a number of technical and economic parameters incorporated in the model. The latter compares the price of electrolytic hydrogen to that of other fuelling options, based on inputs for both electrolytic hydrogen and the other fuelling options.

The comparative portion includes the possibility to assess the economic impact of GHG emissions on the price of electrolytic hydrogen, with respect to other fuelling options. This is done by assigning a fixed monetary value to these emissions ($/ton of CO_2-equivalent), which vary depending on the fuel option considered, and as a function of the electricity mix in the case of electrolytic hydrogen.

The specific cost of hydrogen, U, is simply obtained from the following ratio:

$$U = \frac{C}{Y} \tag{3.1}$$

where U = specific cost of electrolytic hydrogen ($/kg)
C = annual cost to produce electrolytic hydrogen ($/yr)
Y = annual hydrogen production from dispensing station (kg/yr)

The annual cost to produce electrolytic hydrogen, C, is defined as:

$$C = C_c + C_e(+C_{GHG}) \tag{3.2}$$

where C_c = capital, operating and maintenance cost ($/yr)
C_e = annual energy cost ($/yr)
C_{GHG} = relative additional cost/saving related to GHG emissions ($/yr)

C_c and C_e are always positive values, as they correspond to real costs associated with the two principal economic components of water electrolysis, i.e. capital and energy costs. Consequently, they are always included in the calculation of C.

On the other hand, C_{GHG} is treated as a relative term whose value can be either positive (in the case of higher GHG emissions than the alternative fuelling option considered) or negative (i.e. a credit, in the case of lower GHG emissions than the alternative fuelling option considered). The value of C_{GHG} depends on several inputs for both the electrolytic hydrogen and alternative fuelling option to which electrolytic hydrogen is compared. As a result, C_{GHG} is not a real cost or saving, but rather an indicator of the economic advantage of electrolytic hydrogen related to GHG emissions reduction. The model allows C_{GHG} to be included or omitted in the calculation of C, as reflected by the parentheses in equation 3.2. Although somewhat artificial, this component of the hydrogen cost offers a guideline for the relative impact of policy based on the economic evaluation of GHG emissions.

The annual hydrogen production, Y, is determined by the fuelling needs of the vehicles served by the electrolytic hydrogen dispensing station.

$$Y = V * \frac{M}{f_e} \tag{3.3}$$

where V = number of vehicles served by the fuelling station

M = average annual mileage of a vehicle (km/yr)

f_e = average fuel economy (km/kg H_2)

The fuel economy, f_e, in kilometres per kilogram of hydrogen, can be estimated either directly from published data or by converting the energy requirements of a typical FCV, expressed in terms of equivalent gasoline fuel economy. Most published studies [4, 5, 40] express the fuel economy of direct hydrogen FCVs in terms of equivalent gasoline fuel economy, as people are generally familiar with this measure. Some studies use the higher heating value (HHV) of the fuels as a basis for equivalence [40], some use the lower heating value (LHV) [4], and others don't specify which one is used [5]. The main argument for LHV comes from the fact that ICE efficiency is traditionally expressed in reference to the LHV energy content of the fuel. The counter argument for HHV is that this value reflects more accurately the true energy content of a fuel. For consistence in this research, the HHV-basis is always the one used when expressing an equivalent gasoline fuel economy for hydrogen or methanol. See Appendix B for fuel economy conversion. Figure 3.1 below presents a schematic of the model's structure.

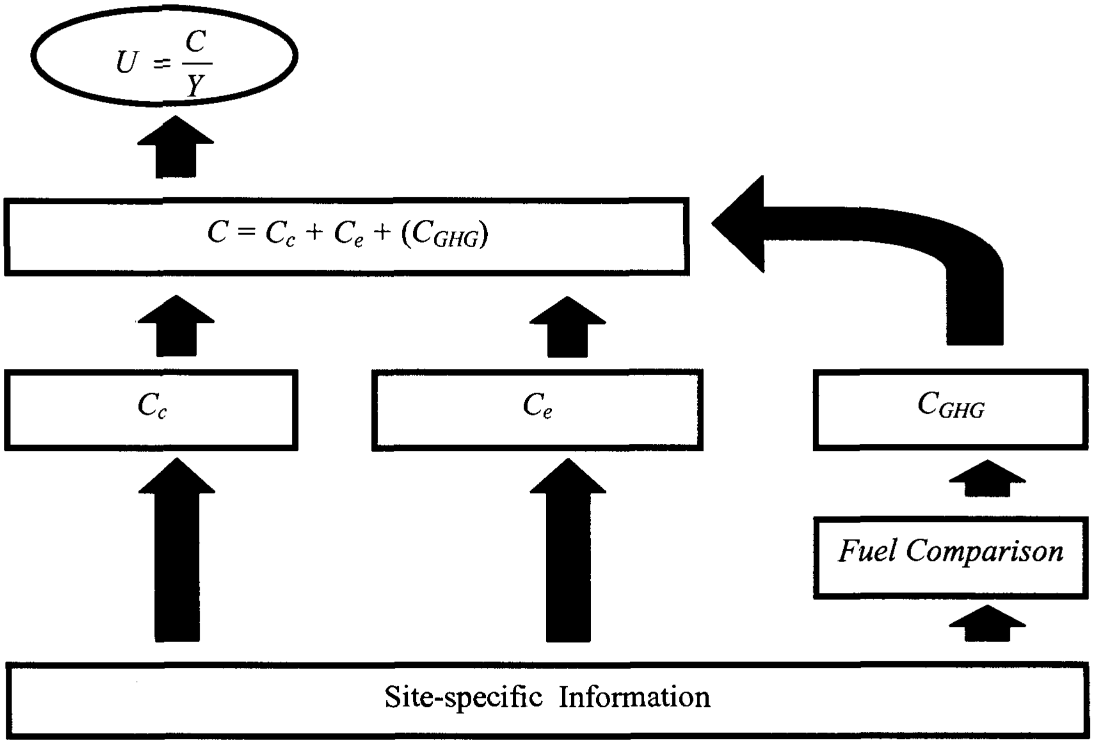


Figure 3.1: General structure of the cost model.

3.2.1 C_c: Capital and Operating Cost

Essentially, the capital and operating cost component considers all the expenses that are associated with the electrolytic hydrogen station, with the exception of the energy cost. It includes the initial installed capital cost, maintenance, major parts replacement, insurance, property taxes, etc. It also takes into consideration economic parameters, such as the expected rate of return on capital investment.

The annual capital and operating cost, C_c, is expressed as a fraction of the electrolytic hydrogen dispensing station's total installed capital cost, C_{cap}. If extraordinary expenses occur at later points, they are distributed over the lifetime of the station to reflect their impact on the annual capital and operating cost, C_c.

$$C_c = C_{cap}(CRF_e + op + ins + t) + CRF\left(\sum_i \frac{E_i(n)}{(1+d)^n}\right) \tag{3.4}$$

where C_{cap} = total installed capital cost of H_2 dispensing station: electrolyzer, compressor, hydrogen storage and associated balance of plant

CRF = capital recovery factor

CRF_e = effective capital recovery factor

op = operating and maintenance costs (% of C_{cap})

ins = annual insurance (% of C_{cap})

t = annual property taxes (% of C_{cap})

E_i = i^{th} extraordinary expense on n^{th} year ($)

d = discount rate (%)

The model allows four distinct capital costs to be included in C_{cap}: electrolyzer, e, compressor, c, hydrogen storage, s, and a miscellaneous one called balance of plant, x. In the scenarios used for sensitivity analysis, only the first three categories are assigned a value, whereas related equipment is combined with either one of them. For example, the hydrogen dispensing equipment cost is included in the compressor portion and the power systems and controls' cost is incorporated in the electrolyzer portion. However, the balance of plant component, x, allows for more flexibility when there is a need to treat some peripheral components separately.

C_{cap} is therefore defined as:

$$C_{cap} = (e + c + s + x) \tag{3.5}$$

where e = capital cost of electrolyzer ($)

c = capital cost of compressor ($)

s = capital cost of storage ($)

x = capital cost of balance of plant ($)

Each of these capital cost components depends on the size of the electrolyzer station, which is in turn largely determined by the number of vehicles to be served. The maximum required hydrogen production flow in Nm^3/h, Q_{H2max}, is obtained from:

$$Q_{H2\max} = \left(\frac{Y}{365 * 24} \right) * 11.126 * \frac{R_{pd}}{f} \tag{3.6}$$

where Y = annual hydrogen production from dispensing station (kg/yr)

R_{pd} = ratio of peak hydrogen production to average demand

f = capacity factor

The numerical values are merely for conversion from annual to hourly production rate, and from kilogram to normal cubic meter (Nm^3) of hydrogen.

In addition to the expected average hydrogen demand from FCVs, the electrolyzer station must be able to handle various fluctuations in demand due to statistical surges, as well as daily, weekday-weekend and seasonal variations. These fluctuations must be accommodated by some combination of hydrogen storage and load following by the electrolyzer system. The ratio of peak hydrogen production to average demand, R_{pd}, accounts for the load following portion. If for instance $R_{pd} = 1.2$, it means the electrolyzer's nominal production capacity is sized 20% higher than the expected average demand. Moreover, it is assumed that any electrolyzer can operate at production rates above this nominal output for short periods of time, although possibly at lower efficiency [43].

The capacity factor, f, essentially accounts for the fact that the electrolyzer typically would be operated less than 24 hours a day to take advantage of lower electricity rates, which affects directly the size of the electrolyzer. For example, an electrolyzer operating 12 hours a day on off-peak electricity rates would have a capacity factor of 0.5, and would therefore be sized for about twice the production rate of an equivalent electrolyzer operating around the clock.

The maximum hydrogen production rate can also be expressed in terms of the energy content (HHV value) of the hydrogen produced, k_{out}, in kilowatt (kW).

$$k_{out} = 3.5418 * Q_{H2\max} \tag{3.7}$$

The conversion factor between Q_{H2max} and k_{out} comes from:

$$1 \frac{\text{Nm}^3\,\text{H}_2}{\text{h}} \equiv 1 \frac{\text{Nm}^3\,\text{H}_2}{\text{h}} * \frac{1\ \text{kg H}_2}{11.126\ \text{Nm}^3\,\text{H}_2} * \frac{141{,}860\ \text{kJ (HHV)}}{\text{kg H}_2} * \frac{1\text{h}}{3{,}600\ \text{s}} \equiv 3.5418\ \text{kW (HHV)}$$

Figure 3.2 presents the variables and simplified equations affecting the four components of the electrolyzer station capital cost C_{cap}. The first line in each sub-box indicates what variables or quantity determine the value of the capital cost component.

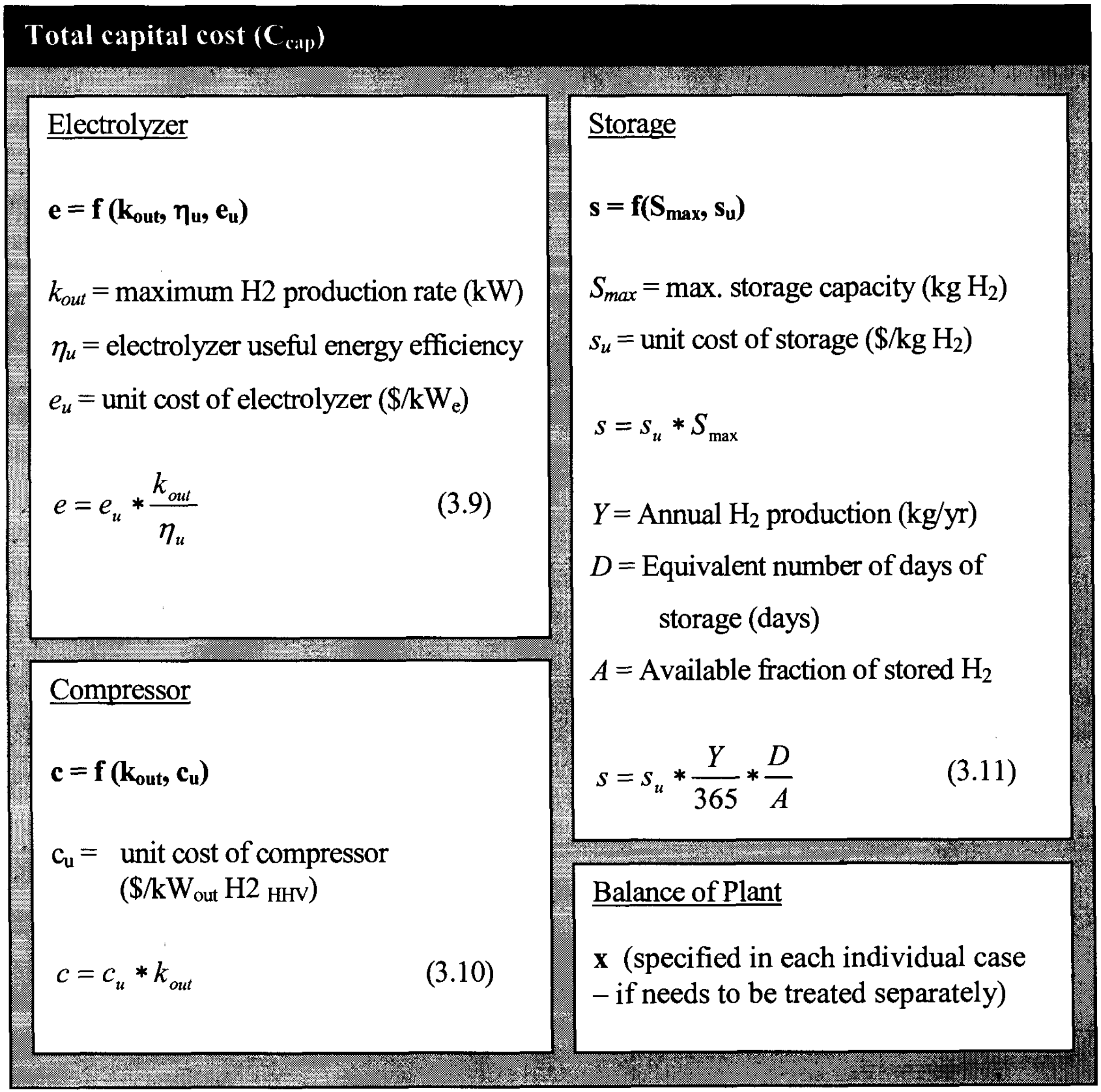
The electrolyzer capital cost, e, is determined by the required maximum hydrogen production rate, k_{out}, the electrolyzer useful efficiency, η_u, and the estimated specific capital cost per kW_e at nominal production, e_u (equation 3.9). The so-called electrolyzer useful efficiency is actually calculated automatically in the model (equation 3.8) and is defined as the following ratio:

$$\frac{\text{Heating value of } H_2 \text{ output (HHV) @ } 25\ ^{\circ}\text{C} \quad [\text{in kWh/kg } H_2]}{\text{Energy input: electricity + NG (HHV)} \quad [\text{in kWh/kg } H_2]}$$

The heating value (HHV) of hydrogen at 25 °C is a fixed value of 39.4 kW/kg H_2 [48]. The energy input to the electrolyzer is nearly always limited to electricity, however natural gas has been added as a possible energy input to investigate the potential effects of natural gas assisted steam electrolysis (NGASE – see Chapter 2). The energy input is calculated from the theoretical energy requirement for water electrolysis at a given temperature, k_{elth} (in kW/kg) divided by the energy efficiency of the electrolyzer, η_e. The main difference between η_e and η_u is that the latter does not consider any of the additional heat contained in the output hydrogen gas (at the electrolysis reaction temperature) to be usable, resulting in a slightly lower value for η_u than η_e; a difference that grows as the temperature of electrolysis is increased.

$$\eta_u = \frac{39.4}{\left(\frac{k_{elth}}{\eta_e}\right)} \tag{3.8}$$

Assuming that hydrogen is stored onboard FCVs as a compressed gas, a compressor system is necessary to bring hydrogen to the desired high-pressure level. The compressor capital cost, c, depends on the required maximum hydrogen production rate, k_{out}, and the estimated specific capital cost of the compressor system per kW_{out} at nominal production, c_u (equation 3.10).



Total capital cost (C_{cap})

Electrolyzer

$e = f(k_{out}, \eta_u, e_u)$

k_{out} = maximum H2 production rate (kW)

η_u = electrolyzer useful energy efficiency

e_u = unit cost of electrolyzer ($\$/kW_e$)

$$e = e_u * \frac{k_{out}}{\eta_u} \quad (3.9)$$

Compressor

$c = f(k_{out}, c_u)$

c_u = unit cost of compressor ($\$/kW_{out}$ H2 $_{HHV}$)

$$c = c_u * k_{out} \quad (3.10)$$

Storage

$s = f(S_{max}, s_u)$

S_{max} = max. storage capacity (kg H_2)

s_u = unit cost of storage ($\$/kg\ H_2$)

$$s = s_u * S_{max}$$

Y = Annual H_2 production (kg/yr)

D = Equivalent number of days of storage (days)

A = Available fraction of stored H_2

$$s = s_u * \frac{Y}{365} * \frac{D}{A} \quad (3.11)$$

Balance of Plant

x (specified in each individual case – if needs to be treated separately)

Figure 3.2: Components included in the electrolyzer station capital cost C_{cap}.

It is assumed that storage tanks would be required to accommodate both the intermittent nature of the electrolytic hydrogen production and irregular load profiles. The hydrogen storage capital cost, *s*, is determined by the maximum storage capacity requirement for the refueling station and the estimated specific capital cost of the storage tanks, s_u.

The storage capacity should cover at least the average daily production of hydrogen, which is likely to be consumed at a different time of the day than it is produced, i.e. off-peak electricity hours. In addition, DTI [43] recommends the equivalent of another full day average production for unexpected equipment failures and surges in demand. The storage capacity can therefore be expressed in "equivalent number of days of storage", D, at the average production rate (equation 3.11). For example, a 2-day storage capacity ($D = 2$) would accommodate a full day's shutdown of the electrolyzer for repairs and maintenance. Also, not all of the hydrogen stored in high-pressure vessels is available, because some of it will remain in the storage tanks as the pressure falls during transfer to the vehicle tanks. DTI quotes an industrial gas company saying that even with multiple tanks and cascade filling, at best 60% of the stored hydrogen can be utilized [43]. The "available fraction of stored hydrogen", A, accounts for this limitation (equation 3.11).

Although the full installed capital cost C_{cap} may have to be spent initially, only a fraction of it needs to be recovered annually. This fraction is called the effective capital recovery factor, CRF_e, which can be determined from the financing parameters. Other more or less fixed annual costs, such as operating and maintenance, op, insurance, ins, and property taxes, t, may also be expressed in terms of the installed capital cost C_{cap}. The sum of these four fractions constitutes the multiplying factor for C_{cap} presented in equation 3.4. Figure 3.3 presents the variables and equations used to calculate the effective capital recovery factor CRF_e, along with the other three components of the multiplying factor.

The capital recovery factor, CRF, is a function of the discount rate, d, and economic recovery period, N, as given by equation 3.12. DTI [43] proposes two different scenarios to calculate the discount rate: one where individual consumers can finance small "electrolyzer fuelling appliances" as part of their home mortgage, and a business case where the electrolyzer station is financed by a company just like any other investment with a given expected after-tax rate of return (corrected for inflation). Equations 3.13 and 3.15 respectively show how the discount rate, d, is calculated for each of these two options. For the home mortgage case, d is equal to the mortgage interest rate corrected for the fact that interest payments are considered to be deductible from income tax. For the business case, d is equal to the after-tax real rate of return, r (corrected for inflation).

Multiplying factor for C_{cap} : $(CRF_e + op + ins + t)$

Capital Recovery Factor

CRF = f (d, N)

d = discount rate
N = recovery period in years

$$CRF = \frac{d}{1-(1+d)^{-N}} \qquad (3.12)$$

To calculate the discount rate d:
i_m = mortgage interest rate
T_p = personal tax rate of home owner
i = general inflation rate
r = after-tax real rate of return on investment
T_b = business tax rate

Home mortgage case

$$d = i_m * (1-T_p) \qquad (3.13)$$

Business case

$$d = r + i(1+r) \qquad (3.15)$$

Effective Capital Recovery Factor

$$CRF_e = CRF \qquad (3.14)$$

$$CRF_e = \frac{\left\{CRF - \frac{T_b}{N}\right\}}{1-T_b} \qquad (3.16)$$

Operating and Maintenance

op = f (C_{cap})

Insurance

ins = f(C_{cap})

Property Taxes

t = f(C_{cap})

Figure 3.3: Components of the annual multiplying factor for C_{cap}.

The "effective capital recovery factor" CRF_e, was artificially created to lead to the more general form of equation 3.4 for the annual capital and O&M cost. CRF_e is identical to CRF for the home mortgage case. For the business case however, CRF_e needs to account for the corporate income tax rate, T_b, which requires the selection of a depreciation schedule. Both DTI and Electrolyser Corporation [43, 42] use straight-line depreciation on the basis of its simplicity, stating that it gives close enough values to the Modified Accelerated Cost Recovery System (MACRS) specified by the American Internal Revenue Service. So this model also adopted the straight-line depreciation schedule, leading to equation 3.16, in accordance with what is specified in engineering economics textbooks [75] for this depreciation schedule.

DTI also considers a third scenario in addition to the home mortgage case and the business case: that of a utility financing the electrolyzer station. This case is treated just like the business case, but with a tax rate T_b equal to zero [43].

The other three costs that are part of the multiplying factor in figure 3.3: operating and maintenance, *op*, insurance, *s*, and property taxes, *t*, are calculated independently and expressed simply as a percentage of the installed capital cost C_{cap}.

One expense which is not considered explicitly in the present model, and which could be added to the operation cost *op*, is the cost of tap water utilized to produce hydrogen from electrolysis. Based on a requirement of approximately 13 litres of water per kilogram of hydrogen [42], and a water price of \$1.00/m^3 in Los Angeles [29], this translates in a cost of water of \$0.013/kg H_2, or in the order of 0.5% of the base case hydrogen price. The average hydrogen requirement for a FCV would necessitate about 7 litres of water per day, i.e. less than a typical toilet flush, or a fraction of current daily water use in industrialized countries (350 litres per person per day in Canada [76]).

Extraordinary expenses (such as catalyst replacement every five years) are calculated in the same way they are treated in the Electrolyser report [42]. The present worth of an extraordinary expense E_i occurring in year n_i is given by:

$$\frac{-E_i(n_i)}{(1+d)^{n_i}} \tag{3.17}$$

This cost must be amortized over the *N* years of the economic recovery period by the capital recovery factor *CRF*. Hence, the calculated annual cost of an extraordinary expense E_i occurring in year n_i is equal to:

$$CRF * \frac{E_i(n_i)}{(1+d)^{n_i}} \tag{3.18}$$

The sum of these extraordinary expenses makes up the last term of equation 3.4, completing the general elements considered in the annual capital and operating cost C_c of an electrolyzer refuelling station.

3.2.2 C_e: Energy Cost

There are two main reasons to treat the cost of energy separately from the capital and O&M costs in the model. 1) It is a variable cost, nearly proportional to the quantity of hydrogen produced, whereas capital and O&M costs are essentially fixed expenses. 2) The cost of electricity is often the dominant component of electrolytic hydrogen's total cost, typically between 50% and 80 % [40, 43, 55].

The simplified process diagram below (figure 3.4) shows the various material and energy inputs and outputs from an electrolytic hydrogen station, with the energy consuming items listed in the central box.

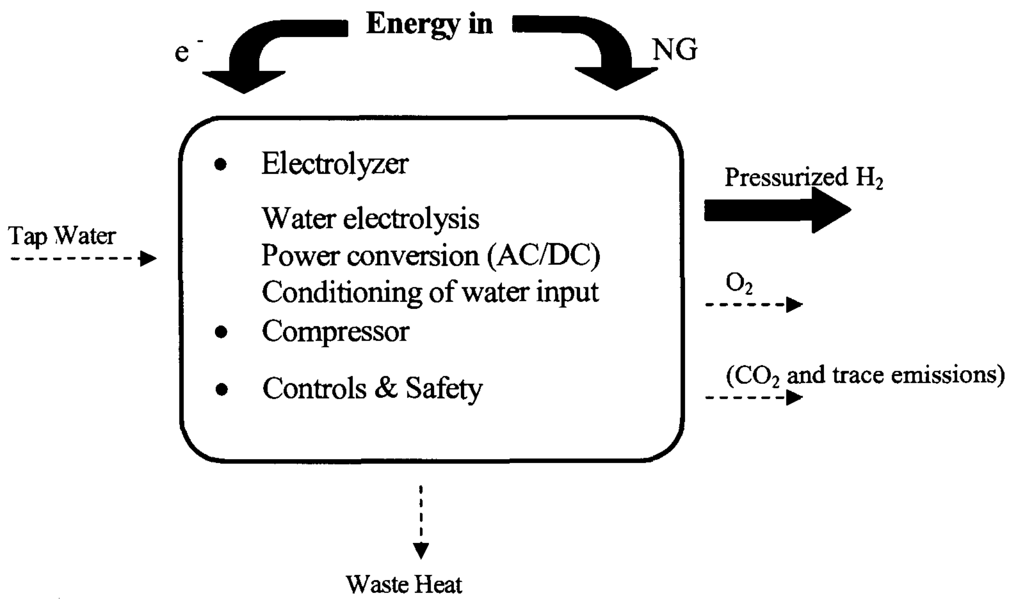


Figure 3.4: Simplified process diagram for electrolytic hydrogen dispensing station

The bold arrows represent material and energy flows that are accounted for in the cost model. Conventionally, the energy required for an electrolytic hydrogen dispensing station is provided in the form of electricity exclusively. However, there is also the possibility in a decentralized scenario to use natural gas for providing a portion of the necessary heat and/or contributing to the electrolysis reaction (NGASE – Natural Gas Assisted Steam Electrolysis). Accordingly, the energy currencies considered as possible inputs for the dispensing station include electricity (e^-) and natural gas (NG).

The energy cost for the electrolyzer includes the electrolysis reaction itself, water conditioning (to bring feed water to electrolysis operating temperature), and AC/DC conversion to provide DC current to the electrolyzer. The input variable for the electrolyzer energy efficiency, η_e (defined later), must account for the combined inefficiencies of both the electrolysis reaction and the AC/DC conversion. For water conditioning, the conservative assumption made in the model is that none of the waste heat from the electrolyzer is used to bring the feed water to electrolysis temperature.

Another conservative assumption is made for the energy cost of the compressor, considering that all of the hydrogen produced needs to be compressed to the nominal storage pressure (e.g. 414 bar or 6,000 psi). In reality, the necessary output pressure from the compressor will increase progressively as each storage tank is filled to nominal storage pressure, in a multiple-tank cascade filling arrangement. Finally, the electricity cost for controls is considered negligible in proportion to the electrolyzer and compressor and therefore omitted in the model.

The flows represented by dotted arrows in figure 3.4 do not affect the energy cost in the model. Feed water is assumed to be at room temperature (25 °C) when it enters the system. No waste heat from the system is considered to be recycled. No energy (chemical or thermal) from the oxygen out flow is considered to be recycled. Oxygen is simply assumed to be vented out.

In the end, the total annual energy cost of the electrolytic hydrogen dispensing station, C_e, can thus be approximated as the sum of the energy costs for the electrolyzer and compressor.

$$C_e = C_{el} + C_{comp} \tag{3.19}$$

where C_{el} = *annual cost of energy for electrolyzer ($/yr)*

C_{comp} = *annual cost of energy for compressor ($/yr)*

Figure 3.5 presents the variables affecting the annual cost of energy for the electrolyzer, C_{el} (\$/yr), along with equation 3.20 used to calculate its value.

Electrolyzer

$$\mathbf{C_{el} = f\,(k_{elth}, \eta_e, \alpha, P_{e-}, P_{NG}, Y)}$$

k_{elth} = theoretical energy required by electrolyzer (kWh/kg H2)
η_e = electrolyzer energy efficiency
α = fraction of required energy provided by NG
P_{e-} = electricity price (\$/kWh)
P_{NG} = natural gas price (\$/GJ)
Y = annual hydrogen production from dispensing station (kg/yr)

$$C_{el} = \frac{k_{elth}}{\eta_e} \times Y \times \left[(1-\alpha)P_{e^-} + 0.0036\alpha P_{NG}\right] \tag{3.20}$$

Figure 3.5: Annual cost of energy for the electrolyzer station.

The theoretical specific energy required by the electrolyzer, k_{elth}, represents the minimum amount of energy necessary to produce one kilogram of hydrogen from water electrolysis, based on thermodynamic considerations. It is given by:

$$k_{elth} = 26.589 \times \left[E_{HHV}(T) + \frac{3RT}{4F} \ln P_i \right] \tag{3.21}$$

where $E_{HHV}(T)$ = higher-heating-value voltage (Volts) as a function of electrolysis temperature T

T = Electrolysis temperature (K)

P_i = Electrolysis pressure (bar)

R = Universal gas constant (8.3144 kJ/kg·mole·K)

F = Faraday constant (96,487)

Equation 3.21 is essentially the product of the fixed number of electrons required to produce one kilogram of hydrogen (26.589 kAh) and the theoretical voltage calculated from the Nernst equation, corrected to account for the additional energy necessary to raise the temperature of the feed water to the electrolysis temperature T.

The higher-heating-value voltage $E_{HHV}(T)$ is obtained from an empirical relationship, based on theoretical values (See Appendix A)

Recall from chapter 2 that for a given temperature, there are three distinct theoretical voltage values for water electrolysis: the reversible voltage (ΔG/2F), the thermoneutral voltage (ΔH/2F) and the so-called higher-heating-value voltage (E_{HHV}); see figure 3.6. E_{HHV} is always the highest of them, including a portion that accounts for the electrolysis reaction itself and a portion for bringing the feed water to electrolysis temperature.

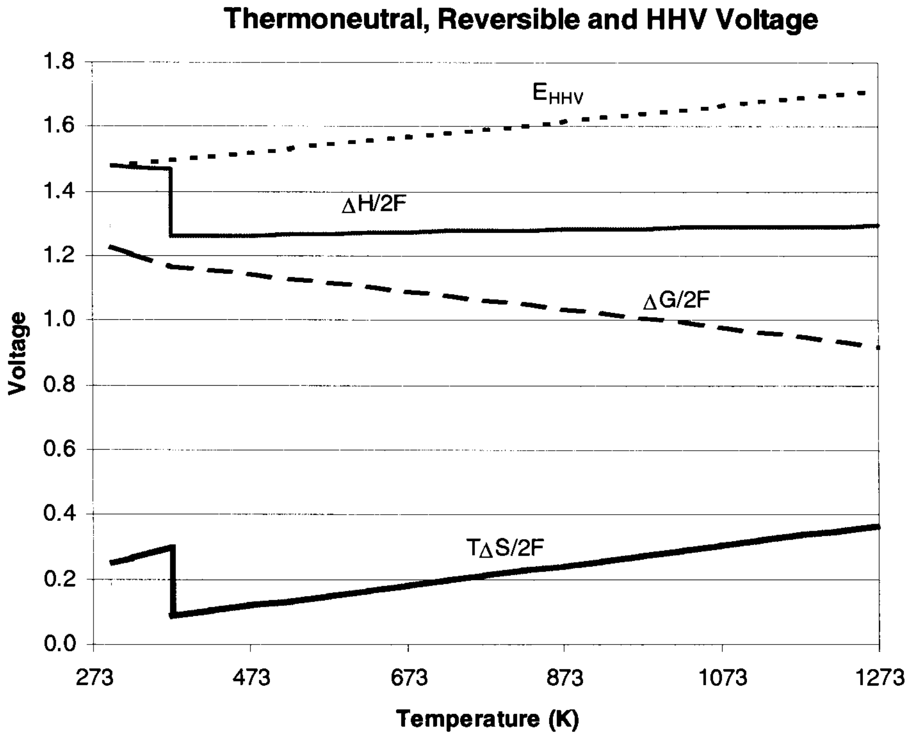


Figure 3.6: Theoretical electrolysis voltages as a function of temperature.

Although other sources consider the thermoneutral voltage (ΔH/2F) as the theoretical reference for calculating the energy efficiency of electrolysis, the present model selected E_{HHV} instead to include the energy required to bring the feed water to electrolysis temperature.

The theoretical specific energy required by the electrolyzer, k_{elth}, can therefore be split in the following two components:

$$k_{elth} = k_{el} + k_{hH2O} \tag{3.22}$$

where k_{el} = theoretical specific energy for electrolysis reaction (kWh/kg H_2)

k_{hH2O} = theoretical specific energy to heat feed water (kWh/kg H_2)

k_{el} can be calculated from:

$$k_{el} = 26.589 \times \left[\frac{\Delta H(T)}{2F} + \frac{3RT}{4F} \ln P_i \right] \tag{3.23}$$

ΔH (T) is obtained from an empirical relationship, based on theoretical values (see Appendix A). ΔH(T)/2F is the thermoneutral voltage for water electrolysis as a function of electrolysis temperature. *ΔH (T)* is calculated for water in a liquid phase below 100 °C and in a gaseous phase above 100 °C.

k_{hH2O} can be calculated from the difference between k_{elth} and k_{el}:

$$k_{hH2O} = 26.589 \times \left[E_{HHV}(T) - \frac{\Delta H(T)}{2F} \right] \tag{3.24}$$

Now, k_{el} may also be divided in two components:

$$k_{el} = k_{el\Delta G} + k_{elT\Delta S} \tag{3.25}$$

where $k_{el\Delta G}$ = specific change in Gibbs free energy to electrolyze water (kWh/kg H_2)

$k_{elT\Delta S}$ = specific heat required for the electrolysis reaction (kWh/kg H_2)

And each of these components may be calculated respectively from equations 3.26 and 3.27:

$$k_{el\Delta G} = 26.589 \times \left[\frac{\Delta G(T)}{2F} + \frac{3RT}{4F} \ln P_i \right] \tag{3.26}$$

$$k_{elT\Delta S} = 26.589 \times \left[\frac{\Delta H(T) - \Delta G(T)}{2F} \right] \tag{3.27}$$

ΔG (T) is obtained from an empirical relationship, based on theoretical values (see Appendix A). ΔG(T)/2F is the reversible voltage for water electrolysis as a function of electrolysis temperature.

The electrolyzer energy efficiency, η_e, which is an input variable to the model, is defined as:

$$\frac{\text{Specific theoretical energy required by electrolyzer } (k_{elth})}{\text{Actual specific energy input: electricity + NG (HHV)}} \qquad \frac{[\text{in kWh/kg } H_2]}{[\text{in kWh/kg } H_2]}$$

Getting back to the annual energy cost for the electrolyzer, C_{el}, once the actual specific energy requirement (in kWh/kg H_2, including both electric and thermal) is determined by k_{elth} and η_e, it is simply multiplied by the annual hydrogen production from the dispensing station Y, and by the average price of energy ($/kWh). The 0.0036 factor in the last term of equation 3.20 simply reflects the conversion of the natural gas price from $/GJ (HHV) to $/kWh.

$$C_{el} = \frac{k_{elth}}{\eta_e} \times Y \times \left[(1-\alpha)P_{e^-} + 0.0036\alpha P_{NG}\right] \qquad (3.20)$$

In cases where natural gas is used as an energy input (in addition to electricity), this approximation has the disadvantage of using a single efficiency value applied equally to both electricity and natural gas.

Figure 3.7 presents the variables affecting the annual cost of energy for the compressor, C_{comp} ($/yr) along with equation 3.28 used to calculate its value.

Compression subsystem

$\mathbf{C_{comp} = f\,(k_{cth}, \eta_c, P_{e^-}, Y)}$
k_{cth} = theoretical energy required for compression (kWh/kg H2)
η_c = compressor efficiency
P_{e^-} = electricity price ($/kWh)
Y = annual hydrogen production from dispensing station (kg/yr)

$$C_{comp} = \frac{k_{cth}}{\eta_c} \times Y \times P_{e^-} \qquad (3.28)$$

Figure 3.7: Annual cost of energy for the compressor subsystem

The theoretical specific energy for the compression of hydrogen, k_{cth}, is defined as the energy required for compressing one kilogram of hydrogen from the electrolyzer pressure, P_i (also considered to be the compressor's inlet pressure), to the maximum storage pressure, P_o (also considered to be the compressor's outlet pressure). In an actual compressor, the compressed gas is heated, making adiabatic compression a better approximation than isothermal compression [43]. The power required for adiabatic compression P_{adiab} (in Watts) is given by:

$$P_{adiab} = M_f RT\left(\frac{\gamma}{\gamma-1}\right)\ln\left[\left(\frac{P_o}{P_i}\right)^{\frac{\gamma-1}{\gamma}} - 1\right] \qquad (3.29)$$

where M_f = gas mass flow rate (mole/s)

R = gas constant (8.3144 J/mol·K)

T = temperature (K)

P_i = inlet pressure to compressor

P_o = outlet pressure

γ = ratio of specific heats for the compressed gas

Since a flow rate of one kilogram of hydrogen per hour is equivalent to 0.1378 mol/s, it means that equation 3.29 can be modified to give the theoretical specific energy for hydrogen compression, k_{cth} (in kWh/kg H_2) for 100% efficient adiabatic compression.

$$k_{cth} = 1.378\times10^{-4} RT \times\left(\frac{\gamma}{\gamma-1}\right)\times\left[\left(\frac{P_o}{P_i}\right)^{\frac{\gamma-1}{\gamma}} - 1\right] \qquad (3.30)$$

with the following assumptions used in the model:

T = temperature = 298 K

γ = ratio of specific heats for hydrogen = 1.42

Compression is always evaluated at 298 K in the model, because temperature can otherwise have a substantial effect on energy requirement for compression. Overall, the evaluation of k_{cth} for the model is considered to be a conservative approximation since it assumes all hydrogen needs to be compressed to the maximum pressure, and the formula used is for single-stage compression, typically less efficient than a more likely multi-stage compression. This is counterbalanced to a lesser extent by the treatment of hydrogen as a perfect gas, which is quite accurate for intermediate pressures, but underestimates the energy requirement for compression by about 20% at 414 bar (6000 psi).

The annual cost of energy for the compressor, C_{comp}, can then be calculated from equation 3.28 based on the value found for k_{cth}, the compressor efficiency η_c (which is an input variable in the model), the annual hydrogen production Y and the price of electricity P_{e-}.

Although not used directly in calculations, the model also gives the total specific energy use, K (kWh/kg H_2) including the electrolyzer and compressor portion:

$$K = \frac{k_{elth}}{\eta_e} + \frac{k_{cth}}{\eta_c} \tag{3.31}$$

This summarizes how the annual energy cost C_e of the electrolyzer station is calculated in the model from the electrolyzer and compressor energy requirements.

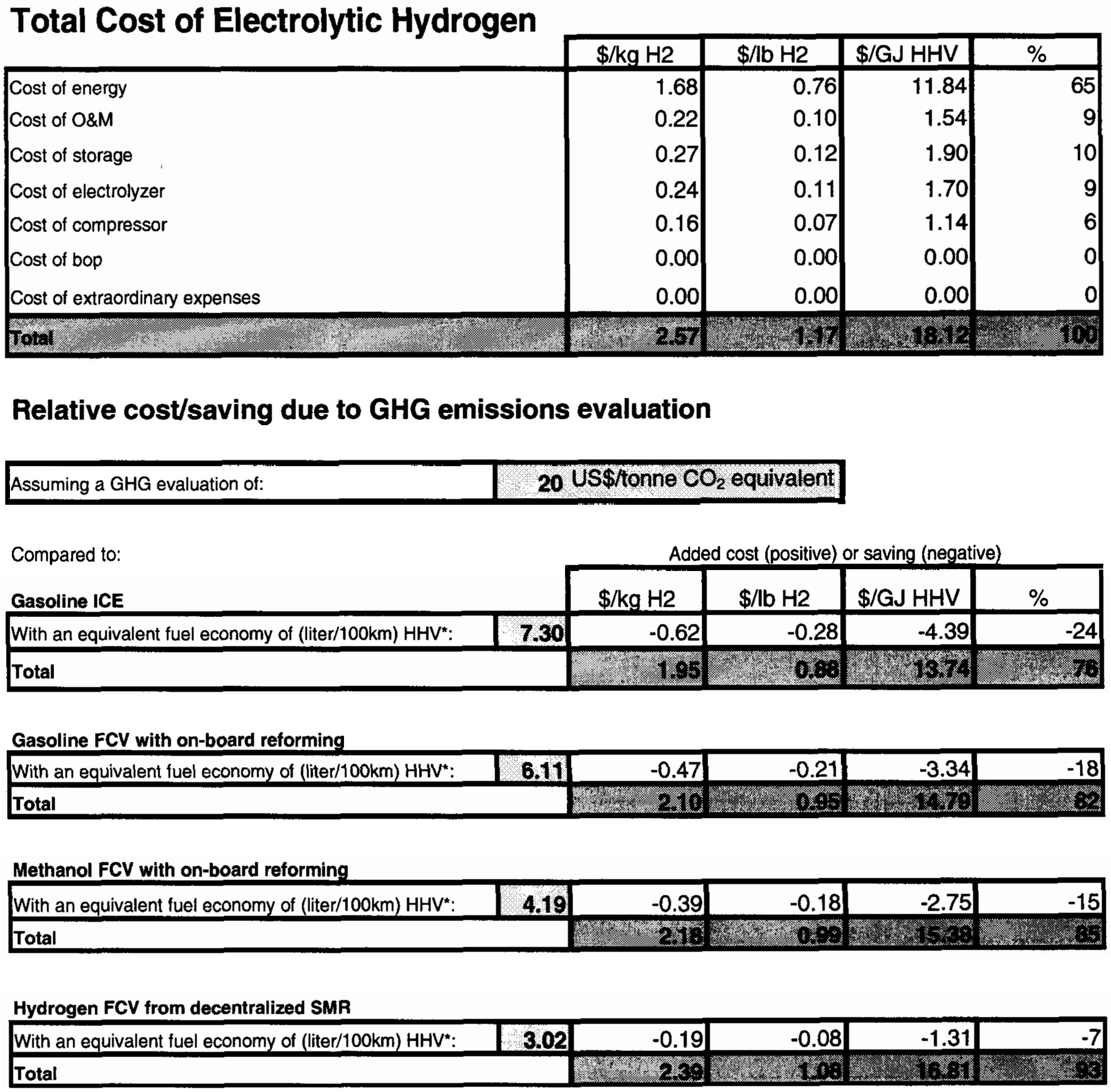
3.2.3 C_{GHG}: Relative Cost or Saving Due to GHG Emission Evaluation

The motivation for including this component in the cost of hydrogen was to give an indication of the potential impact, on the cost of electrolytic hydrogen, of policy relying on a monetary valuation of CO_2 emissions.

Conventionally, this term would be treated as an absolute value added to the cost of all fuel options, to account for the effect of a carbon tax applied on the basis of their respective GHG emissions. However, this type of direct carbon tax would simply add further taxes to the existing ones on gasoline and other hydrocarbon fuels, a scenario that could meet substantial resistance from consumers. Arguably, a more likely scenario for the introduction of hydrogen as a fuel is that lower GHG emissions would be reflected by some credits or lower taxes. The important point for this research was to assess the magnitude of the relative advantage of electrolytic hydrogen versus other fuel options in terms of GHG evaluation, irrespective of whether this is translated later in the form of taxes, credits or other fiscal incentives.

Consequently, it was decided to treat the value of C_{GHG} as a relative term that can be either positive (in the case of higher GHG emissions than the alternative fuelling option considered) or negative (i.e. a credit, in the case of lower GHG emissions than the alternative fuelling option considered). Given its hypothetical value at this point in time, the model offers the choice to include or ignore its effect on the unit cost of hydrogen, calculated from the other two cost components: "capital and O&M" and "energy".

Figure 3.8 presents an example of output results from the cost model in Excel 2000. In the upper portion, it shows the cost distribution for electrolytic hydrogen excluding any influence of GHG evaluation; in the lower portion it shows the effect of considering the relative GHG cost/saving in comparison with each of the alternative fuelling options.



Total Cost of Electrolytic Hydrogen

	$/kg H2	$/lb H2	$/GJ HHV	%
Cost of energy	1.68	0.76	11.84	65
Cost of O&M	0.22	0.10	1.54	9
Cost of storage	0.27	0.12	1.90	10
Cost of electrolyzer	0.24	0.11	1.70	9
Cost of compressor	0.16	0.07	1.14	6
Cost of bop	0.00	0.00	0.00	0
Cost of extraordinary expenses	0.00	0.00	0.00	0
Total	2.57	1.17	18.12	100

Relative cost/saving due to GHG emissions evaluation

Assuming a GHG evaluation of: 20 US$/tonne CO_2 equivalent

Compared to:

		Added cost (positive) or saving (negative)			
Gasoline ICE		$/kg H2	$/lb H2	$/GJ HHV	%
With an equivalent fuel economy of (liter/100km) HHV*:	7.30	-0.62	-0.28	-4.39	-24
Total		1.95	0.88	13.74	76
Gasoline FCV with on-board reforming					
With an equivalent fuel economy of (liter/100km) HHV*:	6.11	-0.47	-0.21	-3.34	-18
Total		2.10	0.95	14.79	82
Methanol FCV with on-board reforming					
With an equivalent fuel economy of (liter/100km) HHV*:	4.19	-0.39	-0.18	-2.75	-15
Total		2.18	0.99	15.38	85
Hydrogen FCV from decentralized SMR					
With an equivalent fuel economy of (liter/100km) HHV*:	3.02	-0.19	-0.08	-1.31	-7
Total		2.39	1.08	16.81	93

Figure 3.8: Example of output from the cost model, showing how the relative GHG cost/saving component can be ignored or included for comparison with each of the alternative fuelling options.

Figure 3.9 presents the variables affecting the annual cost/saving due to GHG evaluation, C_{GHG} (\$/yr) along with equation 3.32 used to calculate its value. Note that since there are four alternative fuelling options to which electrolytic hydrogen can be compared, C_{GHG} can take on more than one value, accounted for by the "j" subscript for each of these four alternatives.

The four fuelling options to which a direct-hydrogen FCV using electrolytic hydrogen can be compared in the model are:

1. Gasoline internal combustion engine (ICE) vehicle
2. Gasoline FCV with on-board reforming
3. Methanol FCV with on-board reforming
4. Direct-hydrogen FCV with H_2 from decentralized steam methane reforming (SMR)

Annual GHG cost or saving

$\mathbf{C_{GHGj} = f\,(alt_j, M, V, GHGel_{km}, GHGaltj_{km}, E_{CO2})}$

alt_j = j^{th} alternative fuelling option to which electrolytic hydrogen is compared (j = 1,2,3,4)
M = average annual mileage (km/year)
V = number of vehicles served by the station
$GHGel_{km}$ = CO_2-equivalent emissions per kilometre from FCV using electrolytic hydrogen (g $CO_{2\,equiv}$/km)
$GHGaltj_{km}$ = CO_2-equivalent emissions per kilometre from vehicle using j^{th} alternative fuelling option (g $CO_{2\,equiv}$/km)
E_{CO2} = monetary evaluation of CO_2-equivalent emissions (\$/ton CO_2)

$$C_{GHGj} = MV * \left(GHGel_{km} - GHGaltj_{km}\right) * \frac{E_{CO2}}{10^6} \qquad (3.32)$$

Figure 3.9: Annual cost or saving associated with GHG emissions.

The general approach is to determine the difference in CO_2-equivalent emissions per kilometre between electrolytic hydrogen and the other fuelling options, and translate this difference into an economic quantity based on the monetary value assigned to CO_2-equivalent emissions. In the context of the model, this potential saving or additional cost per kilometre can be multiplied by the number of vehicles served by the electrolyzer station and the average annual mileage per vehicle to give the total annual GHG-related potential saving or additional cost, C_{GHGj} associated with the station versus each of the four other fuelling options considered.

In equation 3.32, only the CO_2-equivalent emissions per kilometre, respectively $GHGel_{km}$ for electrolytic hydrogen and $GHGaltj_{km}$ for the alternative fuelling option, are not direct input variables in the model. Here is how each of these two values is obtained.

First, $GHGel_{km}$ can be obtained from the CO_2-equivalent emissions per kilogram of electrolytic hydrogen, via the FCV fuel economy:

$$GHGel_{km} = \frac{GHGel_{kg}}{f_e} \tag{3.33}$$

where $GHGel_{kg}$ = CO_2-equiv. emissions per kilogram of electrolytic H_2 (g $CO_{2\ \mathrm{equiv}}$/kg H_2)

f_e = average fuel economy (km/kg H_2)

Now, the value of $GHGel_{kg}$ is obtained from:

$$GHGel_{kg} = CO2_{kWhel} * \left[\frac{k_{elth}}{\eta_e}(1-\alpha) + \frac{k_{cth}}{\eta_c} \right] + 178.3 * \left[\frac{k_{elth}}{\eta_e}\alpha \right] \tag{3.34}$$

where $CO2_{kWhel}$ = CO_2 emissions from electricity generation (g $CO_{2\ \mathrm{equiv}}$ /kWh$_e$ delivered)

k_{elth} = theoretical energy required by electrolyzer (kWh/kg H2)

η_e = electrolyzer energy efficiency

k_{cth} = theoretical energy required for compression (kWh/kg H2)

η_c = compressor efficiency

α = fraction of required energy provided by NG

The value of $CO2_{kWhel}$ is calculated automatically in the model from the specified electricity mix, based on representative figures for CO_2-equivalent emissions from various energy sources. The ones used are based on the Western Europe average [73] and in reasonable agreement with similar figures from a different source at the International Atomic Energy Agency (IAEA) [74].

The GHG emissions associated with each energy source used for power generation are presented in table 3.1, along with an example of electricity mix and the corresponding calculated CO_2-equivalent emissions. To determine the electricity mix, one simply has to select a location (Vancouver, Los Angeles, Paris or "other location") and the electricity mix entered in the site-specific worksheet for that location would be used for calculating $CO2_{kWhel}$.

Mix	Source	GHG emissions *	GHG emissions contribution
%	-	g ($CO_{2\,\mathrm{equiv.}}$)/kWh delivered	g ($CO_{2\,\mathrm{equiv.}}$)/kWh delivered
0	Coal	1071	0
1	Oil	855	9
5	Natural Gas	605	30
0	Nuclear	16	0
91	Hydro	4	4
0	Wind	36	0
0	Solar	193	0
3	Other	0	0
100			42

Table 3.1: Example of electricity mix and specific GHG values used in the model

Equation 3.34 gives the CO_2-equivalent emissions per kilogram of hydrogen by calculating the portion coming from electricity (electrolyzer and compressor) and the portion coming from natural gas, if applicable. The numerical value 178.3 in the second term actually stands for 178.3 grams of CO_2-equivalent emissions per kWh (HHV) of natural gas. It comes from an estimate of CO_2 emissions by use natural gas, approximating natural gas as methane (CH_4) and considering that 100% of it is transformed into CO_2.

$$\frac{1\ \mathrm{g\ CH_4}}{55.5\ \mathrm{kJ\ (HHV)}} * \frac{3600\ \mathrm{s}}{\mathrm{h}} * \frac{44\ \mathrm{g\ CO_2}}{16\ \mathrm{g\ CH_4}} = 178.3\ \frac{\mathrm{g\ CO_{2\,equiv}}}{\mathrm{kWh\ NG\ (HHV)}}$$

These are optimistic assumptions, good enough for the purpose of this model, but which tend to minimize the actual CO_2-equivalent emissions from natural gas. Also, as pointed out earlier, equation 3.34 has the disadvantage of utilizing the same electrolyzer energy efficiency figure for both the electricity and NG portions, minimizing again in most cases CO_2 emissions from NG.

The CO_2-equivalent emissions per kilometre for the "jth" alternative fuelling option, $GHGaltj_{km}$, are adjusted in reference to base case values of CO_2-equivalent emissions per kilometre and corresponding fuel economy for each of the four fuelling options considered.

$$GHGaltj_{km} = \frac{Laltj}{Laltj_{bc}} * GHGaltj_{kmbc} \tag{3.35}$$

where $GHGaltj_{km}$ = CO_2-equivalent emissions per kilometre from vehicle using jth alternative fuelling option (g $CO_{2\,equiv}$/km)

$Laltj$ = fuel economy of jth alternative fuelling option (litre of gasoline-equivalent (HHV) per 100 km)

$Laltj_{bc}$ = base case fuel economy of jth alternative fuelling option (litre of gasoline-equivalent (HHV) per 100 km)

$GHGaltj_{kmbc}$ = base case CO_2-equivalent emissions per kilometre from vehicle using jth alternative fuelling option (g $CO_{2\,equiv}$/km)

The base case values $Laltj_{bc}$ and $GHGaltj_{kmbc}$ used in the model are the ones calculated by the Pembina Institute [5] with the estimated fuel economy values for each of the four fuel options as provided by Ballard Power Systems (all calculated based on an A-Class Mercedes Benz). However, these base case values are input variables that can be changed in the model.

This completes the description of the model's core section for calculating the total annual cost of electrolytic hydrogen from an electrolytic hydrogen dispensing station. This annual cost can then be divided by the station's annual hydrogen production to obtain the relative weight of each cost component in the unit cost of hydrogen U ($/kg). See Appendix C for the actual cost model in Microsoft Excel.

3.3 Site-Specific Information

The "site-specific" worksheet provides some information that can be used elsewhere in the model. The input information can be associated with one of four locations: Vancouver, Los Angeles, Paris or another location to be specified. Some input cells are interactive and will affect calculations in the model; others are there simply for indicative purposes with values that can be input in the appropriate cells. These "interactive" and "non-interactive" cells are identified with different colours in the model.

For a given location, table 3.2 shows the information inputs that influence various aspects of the cost model. It also indicates which of these inputs are interactive cells and which are not.

Site-specific information		Interactive cell	Non-interactive cell
Affecting capital cost			
t	Annual property taxes		X
i_m	Home owner mortgage interest rate		X
T_p	Personal tax rate of home owner		X
i	Inflation rate		X
r	After-tax real rate of return on investment		X
T_b	Business tax rate		X
Affecting energy cost			
P_{e-}	Electricity average retail price		X
P_{e-}	Electricity retail price off-peak		X
	Electricity off-peak rate hours (0-24) affecting capacity factor and size of electrolyzer station		X
P_{NG}	Natural gas retail price		X
Affecting GHG cost/saving			
	Electricity mix (% for each energy source)	X	
Affecting comparison of fuel cost			
	Gasoline retail price ($/litre)	X	
	Tax on gasoline ($/litre)	X	
	Untaxed methanol retail price ($/litre)	X	
	Retail price of hydrogen from decentralized SMR ($/kg H_2)	X	

Table 3.2: Site-specific information input

3.4 Cost Comparison with Other Fuelling Options

A short section within the model allows for cost comparison of electrolytic hydrogen with other fuelling options. The comparison is based on the average fuel cost per kilometre driven. It takes in consideration the particular fuel economy associated with each fuel option, all expressed in litres of gasoline-equivalent (HHV) per 100 kilometres.

For each of the five fuelling options, the cost of fuel per kilometre (with and without the existing fuel tax) is calculated. In the case of methanol and hydrogen, an equivalent tax per unit of energy (HHV) is applied, based on the tax per unit of energy applied on gasoline. The tax level on fuel is automatically adjusted according to the local tax on gasoline for the specified location. The effect of a hypothetical carbon tax, based on the monetary valuation of CO_2-equivalent emissions E_{CO2} (\$/ton CO_2), is also examined for each option. Figure 3.10 shows how this output information is summarized in the model.

Cost Comparison with Other Fuelling Options

		Fuel cost to consumer	Including effect of GHG emission evaluation	
			Added cost	Total
		¢/km driven	¢/km driven	
Gasoline ICE		3.18	0.50	3.67
Untaxed Gasoline ICE		1.66	0.50	2.15
With an equivalent fuel economy of (liter/100km) HHV:	**7.30**			
Gasoline FCV with on-board reforming		2.66	0.39	3.04
Untaxed Gasoline FCV with on-board reforming		1.39	0.39	1.77
With an equivalent fuel economy of (liter/100km) HHV:	**6.11**			
*** Taxed methanol FCV with on-board reforming**		2.57	0.32	2.89
Methanol FCV with on-board reforming		1.70	0.32	2.02
With an equivalent fuel economy of (liter/100km) HHV:	**4.19**			
*** Taxed hydrogen FCV from decentralized SMR**		2.11	0.17	2.28
Hydrogen FCV from decentralized SMR		1.48	0.17	1.65
With an equivalent fuel economy of (liter/100km) HHV:	**3.02**			
*** Taxed hydrogen FCV from decentralized electrolysis**		2.53	0.04	2.57
Hydrogen FCV from decentralized electrolysis		1.90	0.04	1.94
With an equivalent fuel economy of (liter/100km) HHV:	**3.02**			

Tax on fuel
Vancouver
\$/GJ-HHV
5.98

Figure 3.10: Fuel cost comparison on a per-kilometer basis in the model.

3.5 Validation of the Cost Model

Following the model's completion, a series of tests were run with input values borrowed from DTI and Electrolyser's reports [42-43] to ensure that results were in agreement with these previous studies, hence validating most aspects of the cost model. A number of conversions were sometimes required to translate the quantities specified in previous models to the variables used in the present model. In general, the results were in near perfect agreement.

Six different sets of input values were used based on DTI's report to validate the financing aspect, the costs associated with the level of decentralization (size of electrolyzer station) and the hydrogen specific cost distribution ($/lb). Three graphs generated from the current model outputs are nearly identical to graphs presented in DTI's report with respect to these three aspects (figures 3.11, 3.12 and 3.13).

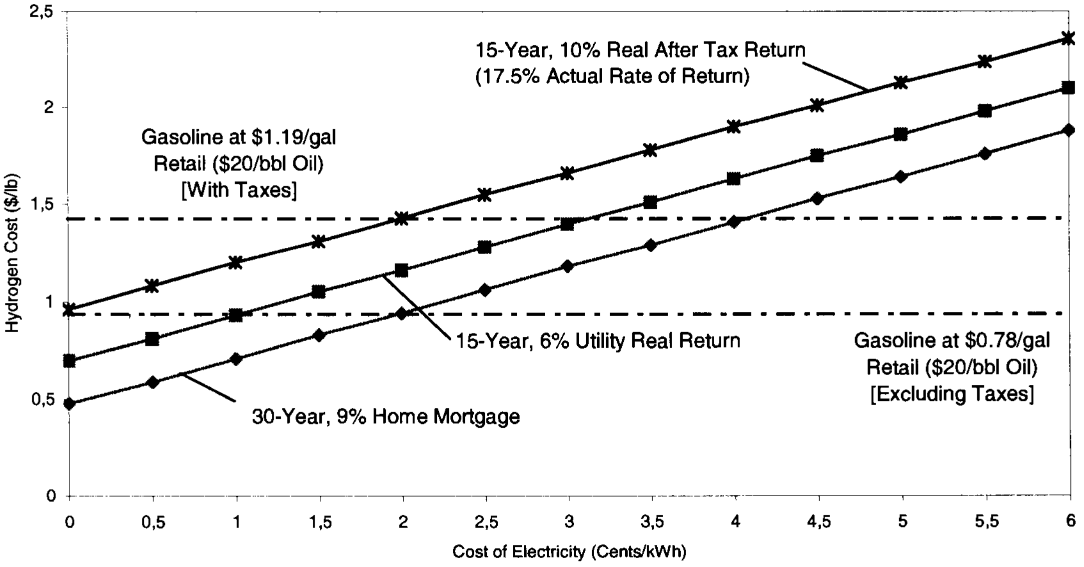


Figure 3.11: Validation of the model's financing aspect reproducing DTI's results.

The energy use for compression is the only aspect that did not agree very closely. For an inlet pressure to the compressor of 100 psi and outlet pressure of 6,000 psi, the energy requirement assumed by DTI is approximately 60% of the requirement assumed by this model (0.065 kWh/kWh H_2 (LHV) = 2.16 kWh/kg H_2 compared to 3.65 kWh/kg for this model). This can be expected since the present model assumes that all of the compressed hydrogen has to be compressed to the maximum pressure (6,000 psi). It simply means that the current model presents a more conservative value. Because of that difference, the compressor inlet pressure input value had to be adjusted to 21.4 bars instead of 6.8 bars (100psi) to obtain the same energy use for compression as DTI.

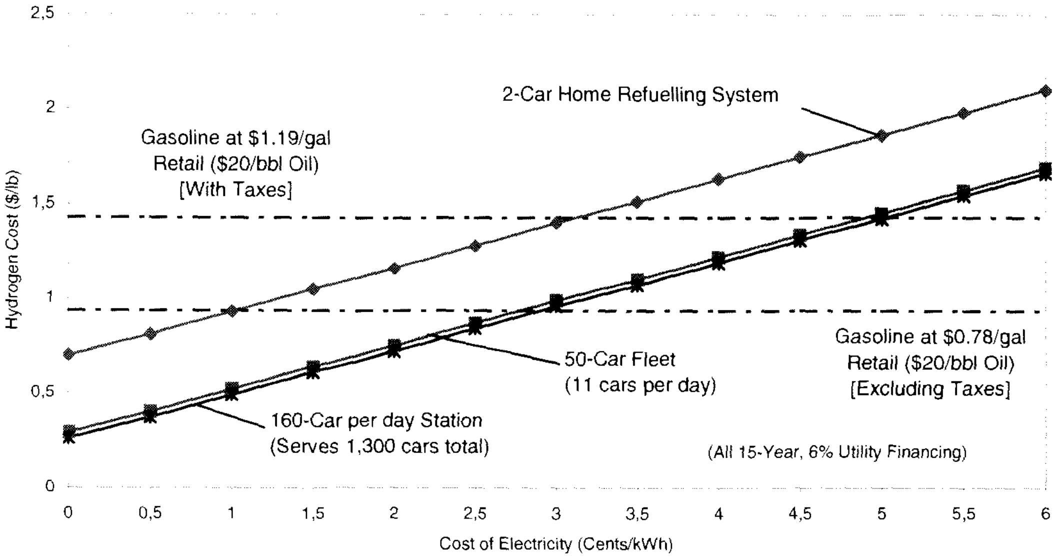


Figure 3.12: The model's ability to reproduce DTI's results for various sizes of electrolyzer stations.

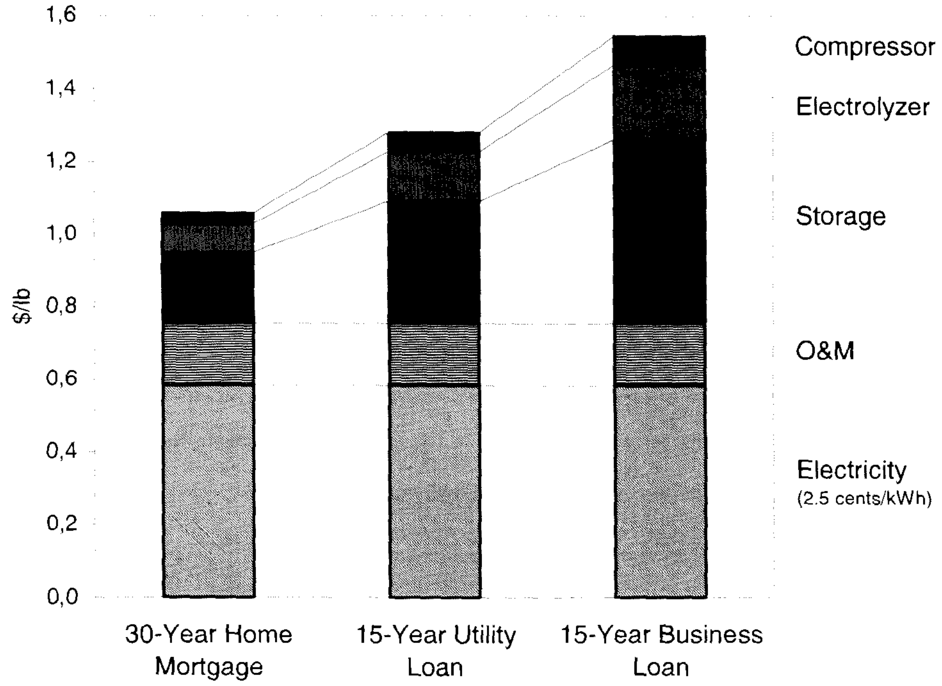


Figure 3.13: The model's ability to reproduce DTI's specific hydrogen cost distribution.

Two other different sets of input values were tested in an attempt to reproduce hydrogen costs presented in the Electrolyser report. Both were for a station comprising 10 hydrogen-vehicle refuelling appliances (HVRA) serving a total of 40 vehicles, considering the estimated capital costs for an annual production of 25,000 and one million HVRAs respectively.

For the one million HVRA case, the value obtained from the model (\$2.23/kg H_2) was approximately 2% higher than the value given in the Electrolyser report (\$2.18/kg H_2). Since energy cost seems to be in agreement (varying electricity price produces identical variations in hydrogen price as in the Electrolyser report), the source of the difference seems to come from the capital and O&M cost. To obtain \$2.23/kg, the economic recovery period was set at 10 years (lifetime specified for HVRA). However, when the economic recovery period is set at 15 years (like suggested by the standard presented in appendix of the Electrolyser report), an identical result of \$2.18/kg is obtained.

For the 25,000 HVRA case, the value obtained from the model (\$2.78/kg H_2) was approximately 8% higher than the value given in Electrolyser's report (\$2.57/kg H_2). Again energy costs seem to be in agreement, suggesting the difference comes from the capital and O&M cost. To obtain \$2.78/kg, the economic recovery period was set at 10 yrs (lifetime specified for HVRA) and O&M annual costs at \$2290 as specified for that level of production. However, when the economic recovery period is set at 15 years (like suggested by the standard presented in appendix of the Electrolyser report) and O&M annual costs set at \$942 (given for 1M HVRAs/yr), the correct price of \$2.57/kg is obtained.

Other aspects of the model, such as CO_2-equivalent emissions calculated from the electricity mix, or the value of the resulting GHG-related cost/saving per kilogram of hydrogen, were tested and validated independently. The end result is a reasonably robust and reliable cost model that can be used for analysis of the cost and competitive position of decentralized electrolytic hydrogen for FCVs.

Chapter 4 – Analysis

4.1 Approach

The main objective of the analysis portion is to identify the issues that have the most influence on the competitive position of electrolytic hydrogen for FCVs, and accordingly, explore possible avenues to minimize the cost of electrolytic hydrogen to the consumer.

The analysis proceeds in two steps. First, it follows the general structure of the cost model and successively looks at the influence of individual input parameters for each of the three cost categories: Capital and O&M, Energy, and GHG Added Cost/Saving. Using the cost model developed, a sensitivity study was performed to identify and quantify the parameters that have the most influence on the price of electrolytic hydrogen to the consumer. The objective at this stage is to get some indications of the relative impact of each parameter, rather than in-depth quantitative analysis. Each parameter examined is also assigned a dominant aspect between "technical", "economic" and "comparative" for the second step of the analysis.

In the second step, parameters to which the price of electrolytic hydrogen appears most sensitive are analyzed and discussed, along with some couplings overlooked in the first step. Here, the analysis follows the approach presented in section 1.6 (*Focus and Methodology of this Study*), which consists of investigating the effects of three increasingly broader aspects that affect the competitive position of electrolytic hydrogen for FCVs. These aspects are respectively designated by the adjectives "technical", "economic" and "comparative" (figure 4.1).

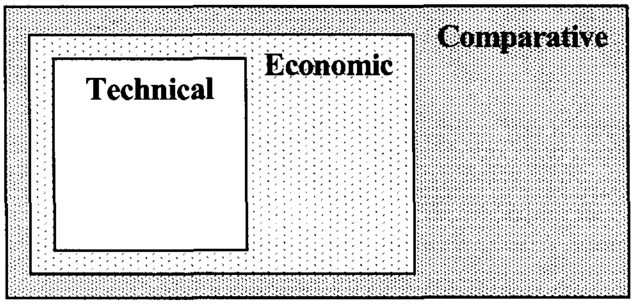


Figure 4.1: Aspects considered in sensitivity analysis.

The technical aspect is concerned with parameters that can generally be influenced by engineering. For instance, the cost of decentralized electrolytic hydrogen could be reduced by clever design of the electrolyzer, the use of inexpensive materials, higher energy efficiency, a hydrogen storage method that requires lower pressure, etc. Note that these potential improvements would ultimately result in a lower cost of electrolytic hydrogen, independently of the location where the electrolytic fuelling station is installed or the way it is financed. The technical aspect is therefore considered to be relatively independent of geo-economic parameters, as opposed to the other two aspects (figure 4.2).

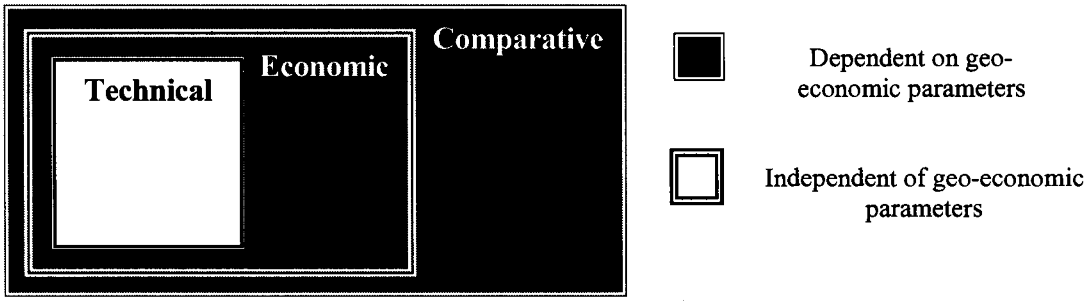


Figure 4.2: Dependence on geo-economic environment.

The economic aspect considered in the context of this analysis deals with variables of an economic nature that influence the cost of electrolytic hydrogen. The financing of the station (by the consumer, a business or a utility), the expected rate of return, the price of electricity, the economic recovery period are all examples of such economic parameters. These parameters affect the cost of electrolytic hydrogen, independently of the specific technology used in the electrolytic fuelling station. Their influence on the cost of electrolytic hydrogen is also independent of the other fuelling options that may be considered for FCVs.

The comparative aspect reflects the fact that the competitive position of decentralized electrolytic hydrogen depends not only on technical and economic parameters that directly influence the unit cost of electrolytic hydrogen, but also on data from other potential fuelling options for FCVs and various implications from taxes or credits (figure 4.3).

Parameters associated with the comparative aspect can have an effect on the competitive position of electrolytic hydrogen by either: 1) affecting directly the unit cost of electrolytic hydrogen ($/kg), or 2) affecting the average fuel cost per kilometre for the electrolytic hydrogen or other fuelling options. For example, a credit for electrolytic hydrogen produced using electricity from clean sources would directly reduce the unit cost of electrolytic hydrogen. On the other hand, an increase in fuel economy of conventional ICE vehicles would do nothing to the unit cost of electrolytic hydrogen, but would affect the difference in fuel cost (¢/km) between the gasoline ICE option and the electrolytic hydrogen FCV option. In the cost model developed, only one comparative criterion is allowed to influence directly the unit cost of electrolytic hydrogen ($/kg). It is the relative advantage in terms of GHG emissions, based on the monetary valuation of CO_2-equivalent emissions.

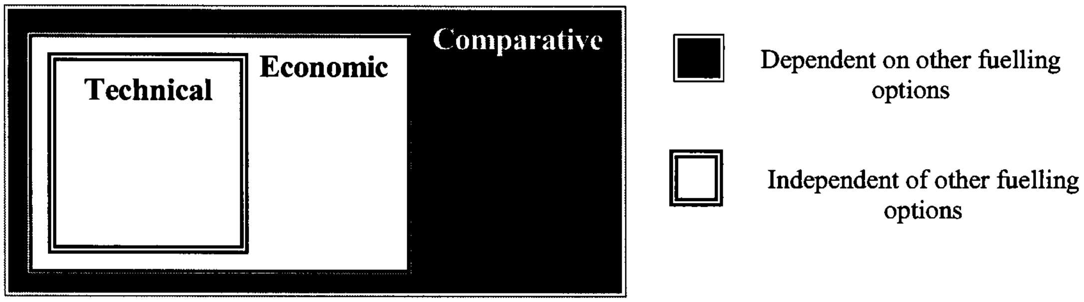


Figure 4.3: Dependence on other fuelling options.

Although the cost model was used extensively to support the analysis presented in the second part of this chapter, additional elements and couplings not explicitly reflected in it are discussed as well. The breakdown of this analysis in three distinct aspects, as described above, may seem constrained to a certain extent, considering that several variables actually affect more than one aspect. Nevertheless, this categorization should help clarify the domain of action for each aspect and its potential impacts on the competitive position of electrolytic hydrogen.

4.2 Base Case for Sensitivity Analysis

A base case was defined for an electrolytic hydrogen fuelling station supporting 100 vehicles (approximately 13 vehicles per day on average, assuming refuelling when tank is about two-third empty). This station size lies somewhere in the middle of the range of 2 to 1000 vehicles supported, considered in this analysis for a decentralized scenario.

One of the options presented in the 1996 Electrolyser report to Ford Motor [42] is used as the primary reference for selecting parameter values of the base case. This source offers the advantage of cost projections from an actual electrolyzer company. A second source used for base case values is the 1995 report from DTI [43]. The full list of base case values is given along with justifications in Appendix D.

The option selected from the Electrolyser report considers a fleet station comprising 10 HVRAs (hydrogen vehicle refuelling appliances), each designed to serve 4 FCVs, for a total of 40 FCVs supported by the station. However the fleet vehicles considered in the Electrolyser report, have a fuel economy about 40% lower and an annual mileage 1.5 times higher than the values used for the base case of this research. The base case fuel economy value selected here (135 km/kg H_2) is similar to the one provided by Ballard Power Systems for a 5-seater Mercedes A-Class FCV [5]. The base case annual mileage used in this research (19,200 km/yr) reflects the average annual North American mileage for light-duty vehicles. The result is that the annual hydrogen demand for 100 vehicles in the base case (14,222 kg/yr or 142 kg/FCV-yr) is within 1% of the corresponding value for the 40-FCV fleet station presented in the Electrolyzer report. This allows direct comparison and validation of the cost estimates, for the various components of the base case.

The Electrolyser report estimated the capital cost of these fleet stations for three cases: first 100 systems, 1000 systems (considering a production of 25,000 HVRAs/yr) and 1000 systems (considering a production of 1 million HVRAs/yr). The 25,000 HVRAs/yr case is used as a reference point for the base case capital cost. This translates into enough capacity to support up to 100,000 FCVs globally, a realistic figure by the end of this decade, representing less than 0.3% of world annual car sales.

It is assumed that the electrolytic hydrogen stations are financed by a utility, with a real rate of return of 6%/yr (or a discount rate of 8.86%/yr taking into consideration an inflation rate of 2.7%), resulting in a capital recovery factor *CRF* of 0.1230. These are the same values used for the utility financing option in DTI's report [43].

Other important figures used for the base case are: an electricity rate of 3¢/kWh with an electrolyzer efficiency of 80% (HHV), an electrolyzer unit cost (e_u) of \$200/kW$_e$ (including electrolyzer, power system and controls), a compressor unit cost (c_u) of \$170/kW$_{out}$ (including dispensing equipment), a storage cost (s_u) of \$200/kg H_2 and a hydrogen storage capacity equivalent to 2 days of average production (D =2). Annual O&M costs are estimated at 4% of the total installed capital cost (2% for operation and maintenance costs, 1.5% for insurance and 0.5% for property taxes). See Appendix D for the complete list of base case values.

In general, the values used for the base case could be characterized as moderately optimistic for the entry market stage. The unit cost of delivered hydrogen obtained for the base case is in the same range or slightly higher than the values found in the Electrolyser report for this production volume (25,000 HVRA's/yr); and anywhere between 0 to 40% lower than other estimates [4,28-29]. Figure 4.4 shows the distribution of the delivered hydrogen cost for the base case (\$2.57/kg H_2 or \$1.16/lb or \$18.12/GJ (HHV)).

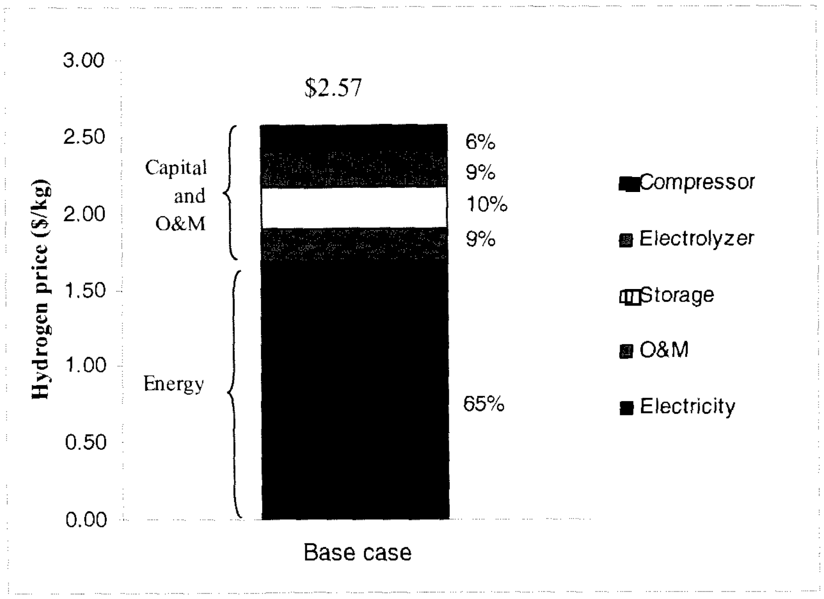


Figure 4.4: Distribution of the delivered hydrogen price for the base case

4.3 Sensitivity Analysis Following the Cost Model Structure

4.3.1 Capital and O&M Cost

The capital cost of an electrolyzer station is obviously related to its size, which in turn depends on the demand for hydrogen. As explained in section 3.2, this demand is determined by the number of vehicles supported (V), their average fuel economy (f_e) and their annual mileage (M). In the model, these parameters directly affect the size and total cost of the electrolyzer station, but their impact on the unit cost of hydrogen (\$/kg) is not explicitly accounted for. Other input variables must be modified to reflect their indirect impact on the unit cost of hydrogen. For example, a low number of vehicles supported (V) may translate into a higher hydrogen storage requirement (D) to deal with larger fluctuations in demand.

Unless specified otherwise, the model assumes the same specific capital cost for the electrolyzer ($/kW$_e$), compressor ($/kW$_{out}$) and storage ($/kg H_2) components, regardless of the electrolyzer station's size. This is a reasonable assumption, consistent with DTI's study [43], considering that the higher specific cost normally associated with smaller units could be compensated by larger volumes produced.

To help visualize the relative size of electrolyzer stations, table 4.1 gives the hydrogen production rate, power requirement and approximate footprint for the range considered in this analysis (2-1000 FCVs supported per station). These estimates are calculated based on a capacity factor f of 0.7 (operating 70% of the day) and a peak-to-demand ratio R_{pd} of 1.5, 1.2 and 1.1 respectively for V = 2, 100 and 1000 vehicles supported. The change of peak-to-demand ratio for each station size explains why their nominal power rating and maximum hydrogen production rate are not exactly proportional to the number of vehicles supported.

Number of vehicles supported	**Electrolyzer station size**				
	Maximum H_2 production rate			**Power**	**Approximate Footprint**
	(Nm^3/h)	**(kg/h)**	**(kg/day)**	**(kW_e)**	**(m^2)**
2	0.8	0.07	1.2	3.5	[1]Electrolyzer station: 1 H_2 storage: 1-2.5
100	31	2.8	47	140	[2]Electrolyzer station: 10-30 H_2 storage: 10-20
1000	284	26	429	1280	[3]Electrolyzer station: 30-90 H_2 storage: 100-200

Table 4.1: Electrolyzer station relative sizes.

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[1] Estimated from Electrolyser report [42]; storage footprint based on enough hydrogen to provide refuelling for two base case FCVs. Considers 2-4 times the area occupied by the compressed gas itself for a 1-metre high volume.

[2] Estimated from Electrolyser report [42]; storage estimated like above, also in agreement with approximate storage footprint in Electrolyser report.

[3] Estimated from Electrolyser report and Japanese PEM electrolyzer station [42, 51], storage estimated like above.

The parameters directly affecting the "Capital and O&M cost" (C_c) in the model are listed in table 4.2 (with the exception of the electrolyzer efficiency η_e, included in the Energy cost section that follows). A range of values for each of these parameters is applied to evaluate the corresponding sensitivity of the hydrogen cost. The choices of range values are generally explained in Appendix D. The dominant aspect(s) influenced are identified for discussion in the second part of the analysis: "T" stands for technical, "E" for economic and "C" for comparative. Here, parameters of the Capital and O&M cost are associated relatively equally with the technical and economic aspects.

Parameter		Units	Range considered	Base case	Dominant aspect
R_{pd}	Ratio of peak H_2 production to average demand	-	1.1 – 1.5	1.2	T, E
f	Capacity factor	-	0.25 – 1	0.7	E, T
e_u	Electrolyzer unit cost	\$/kW$_e$	100 – 1,000	200	T, E
c_u	Compressor and dispenser unit cost	\$/kW$_{out}$ – HHV	70 – 500	170	T, E
s_u	Hydrogen storage unit cost	\$/kg H_2 storage capacity	50 - 500	200	T, E
D	Equivalent days of storage	days	2 – 11.4	2	T
A	Available fraction of stored hydrogen	-	0.4 – 1	0.5	T
CRF_e	Capital recovery factor (effective)	-	0.0715 – 0.3280	0.1230	E
op	Operation and maintenance	% of C_{cap}	0.5 – 4	2	T, E
ins	Annual insurance	% of C_{cap}	0 – 3	1.5	E
t	Annual property taxes	% of C_{cap}	0 – 3	0.5	E
E_i (n_i)	Extraordinary expense E_i occurring in year n_i (i = 1,2,3…)	\$	0 – 50% of C_{cap} every 5 years	0	T, E

Table 4.2: Parameters used to calculate the annual capital and O&M cost (C_c) of a decentralized electrolytic hydrogen dispensing station.

Figure 4.5 shows the sensitivity of the unit price of hydrogen to each of theses parameters, based on the range considered in table 4.2.

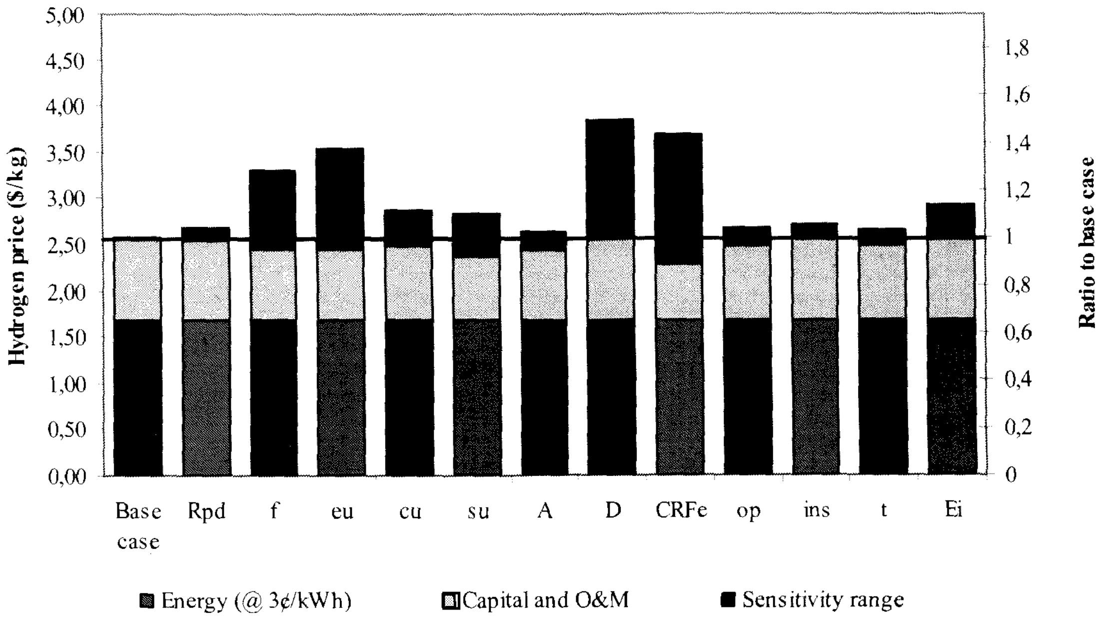


Figure 4.5: Sensitivity of hydrogen price to parameters affecting the Capital and O&M cost (C_c).

A look at figure 4.5 reveals four dominant parameters that have more impact on the capital cost of the electrolytic hydrogen station: the effective capital recovery factor CRF_e, the hydrogen storage capacity D, the electrolyzer unit cost e_u, and the capacity factor f. Their respective sensitivity ranges correspond to 54%, 49%, 42% and 33% of the base case hydrogen price. In addition to the parameter D, the cost for hydrogen storage is also affected by s_u and A, suggesting an even greater sensitivity of the hydrogen price to the storage aspect.

Consequently, four items that should be examined more closely in the second part of the analysis are the financing scheme (related to CRF_e), the storage aspect (D, s_u and A), the electrolyzer cost (e_u), and the capacity factor (f).

4.3.2 Energy Cost

Table 4.3 shows the list of parameters directly affecting the Energy cost (C_e) in the model, with their respective range considered for sensitivity analysis. This portion is called "Energy cost" rather than "Electricity cost", to account for the possible use of natural gas in providing part of the energy required for electrolysis. By appropriate extension, it is even possible to consider the use of available heat at a free cost by adjusting the parameter α (which normally determines the portion of energy provided by natural gas) as required, and by setting the cost of natural gas to zero.

The sensitivity of the unit price of hydrogen to each of the "Energy cost" parameters is shown in figure 4.6, based on the range considered in table 4.3. Again, the choice of minimum and maximum range values for most parameters is explained in Appendix D.

Parameter		Units	Range considered	Base case	Dominant aspect
η_e	Energy efficiency of electrolyzer	%	60 – 100	80	T
η_c	Compressor efficiency	%	30 – 100	75	T
P_{e-}	Electricity price	$/kWh	0.01 – 0.07	0.03	E, C
P_{NG}	Natural gas price	$/GJ (HHV)	3.00 – 8.00	3.00	E, C
T	Electrolysis temperature	°C	70 – 1000	70	T
P_i	Electrolysis pressure (also inlet pressure to compressor)	bar	2 – 414	2	T
P_o	Outlet pressure from compressor (also hydrogen storage pressure)	bar	2 – 414	414	T
α	Fraction of energy required for electrolysis provided by natural gas (for NGASE)	-	0 – 1	0	T

Table 4.3: Parameters used to calculate the annual energy cost (C_e) of a decentralized electrolytic hydrogen dispensing station.

Most of the "Energy cost" variables are associated with the technical aspect, although the one parameter with the largest impact by far, the electricity price (P_{e}-), is linked to the economic aspect (see figure 4.6).

Of the four parameters with a larger impact on the unit price of hydrogen, only two are associated with conventional electrolysis: the price of electricity (P_{e}-) and the energy efficiency of the electrolyzer (η_e). Their sensitivity ranges correspond to 131% and 36% of the base case hydrogen price respectively. In the model, the Capital and O&M cost portion is also modestly affected by the efficiency of the electrolyzer, which explains a slightly lower Capital and O&M cost portion for the parameter η_e in figure 4.6.

The other two parameters are the portion of energy provided by natural gas (α) for a hypothetical commercial version of NGASE, and the price of natural gas (P_{NG}). Their sensitivity ranges correspond to 37% and 35% of the base case hydrogen price respectively. For assessing the sensitivity to the natural gas price (P_{NG}), only the case $\alpha = 1$ was considered, which explains why the sensitivity range for this parameter does not cover the base case.

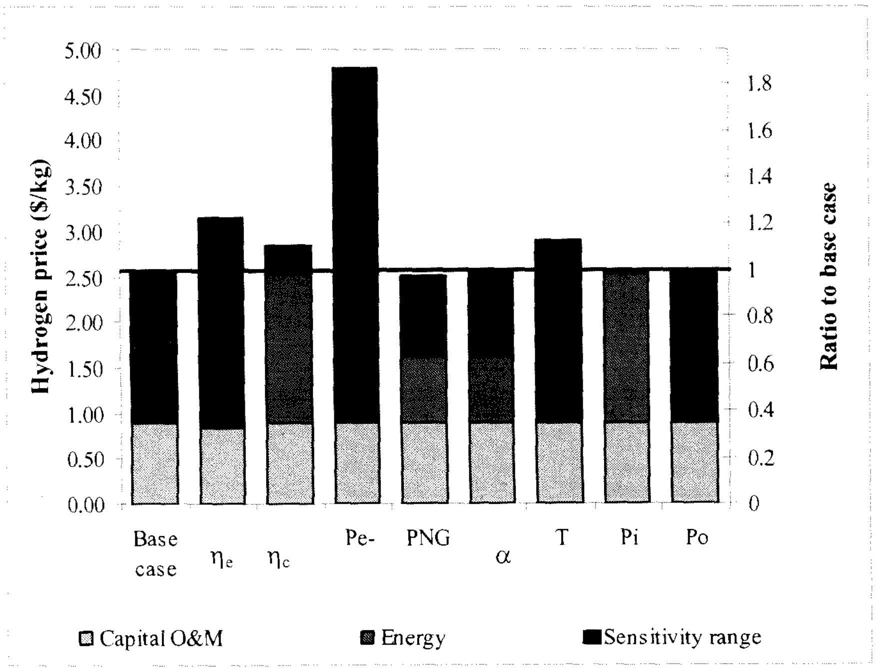


Figure 4.6: Sensitivity of hydrogen price to parameters affecting the Energy cost (C_e).

The price of electricity (P_e-), the energy efficiency of the electrolyzer (η_e) and the potential impact of using natural gas to provide part of the energy requirement (α and P_{NG}) should therefore be the object of more attention in the second part of the analysis.

4.3.3 GHG Added Cost or Saving

The base case does not include any consideration of the GHG aspect; and so far, no "GHG added cost or saving" component has been included in the sensitivity analysis. Table 4.4 shows the parameters directly affecting the GHG added cost or saving (C_{GHG}) in the model. For the purpose of this analysis, only two parameters are allowed to vary: the monetary valuation of CO_2 (E_{CO2}) and the electricity mix. The effects of potential fuel economy improvements are discussed in the second part of the analysis.

Parameter		Units	Range considered	Base case	Dominant aspect
E_{CO2}	Monetary valuation of CO_2 emissions	\$/ton CO_2 eq	0 – 50	0	C, E
Electricity mix	Coal Oil Natural gas Nuclear Hydroelectric Wind Solar Other (CO_2-free)	% (g $CO_{2\,eq}$/kWh)	CO_2-free mix – 100% coal (0 –1,071)	CO_2-free mix	C, E
f_e	Fuel economy of FCV with electrolytic hydrogen	km/ kg H_2 (gasoline equiv, L/100km)	-	135 (3.02)	C
Fuel economy of other fuelling options	FCV with hydrogen from decentralized SMR	gasoline equiv, L/100km	-	3.02	C
	Methanol FCV with on-board reforming		-	4.19	C
	Gasoline FCV with on-board reforming			6.11	C
	Gasoline ICE vehicle			7.30	C
CO_2 equivalent emissions of other fuelling options	FCV with hydrogen from decentralized SMR	g CO_2 equiv./ km	-	86	C
	Methanol FCV with on-board reforming		-	162	C
	Gasoline FCV with on-board reforming		-	193	C
	Gasoline ICE vehicle		-	248	C

Table 4.4: Parameters used to calculate the annual "GHG added cost or saving" (C_{GHG}) associated with a decentralized electrolytic hydrogen dispensing station

All the parameters in table 4.4 are associated with the "comparative" aspect for the second part of the analysis. The monetary valuation of CO_2 emissions (E_{CO2}) and the electricity mix are also associated with the economic aspect, since they both depend to a large extent on economic considerations. The only parameter associated with the technical aspect that has a minor indirect effect on the GHG added cost or saving component is the electrolyzer energy efficiency (η_e), which is kept constant at the base case value of 80% (HHV) for this part of the sensitivity analysis.

All the base case values for the fuel economy and CO_2-equivalent emissions of other fuel options are based on values used in a report written by the Pembina Institute in 2000 [5] to compare “well-to-wheels” GHG emissions of various fuelling options for FCVs. A Mercedes-Benz A-Class (5 seats) is used as the reference vehicle for each fuelling option, and the fuel economy is always calculated based on the U.S. Environmental Protection Agency (EPA) combined urban and highway driving cycle (45% highway and 55% city driving). The fuel economy values for an A-Class Mercedes-Benz FCV, running on compressed hydrogen, methanol or gasoline from an on-board fuel processing system, were obtained from Ballard Power Systems as their “probable case”. The fuel economy of the gasoline ICE A-Class Mercedes-Benz was obtained from a Mercedes-Benz dealer, based on reformulated gasoline as the fuel.

The base case fuel economy selected for the compressed hydrogen FCV is 135 kilometres per kilogram of hydrogen (or 3.02 litres per 100 km of gasoline equivalent), a value that is within 1% of the projected value by Ballard Power Systems. The same fuel economy value is therefore applied for both the FCV running on electrolytic hydrogen and the one running on hydrogen from decentralized SMR, since the vehicle sees no difference in the hydrogen source. See Appendix B for more details on fuel economy conversions.

The so-called “well-to-wheels” GHG emissions include emissions from the whole energy chain, from extraction of the fuel to its processing, distribution and final use, as opposed to tailpipe emissions alone. The Pembina report explains clearly how emissions at the various steps were calculated for each fuelling option considered and which reference sources were used [5].

Figure 4.7 presents the sensitivity of the unit price of hydrogen to the monetary valuation of CO_2 and the electricity mix. These two issues are coupled as a monetary valuation of CO_2 is necessary to translate in economic terms the advantage of electricity with low GHG emissions. An increase in CO_2 monetary valuation merely amplifies the corresponding credit for "clean" electricity or surtax for "high-GHG" electricity. The graph of figure 4.7 may appear less straightforward to interpret than the previous ones, due to the fact that the "GHG cost/saving" is treated as a relative quantity that can be positive (added cost) or negative (saving).

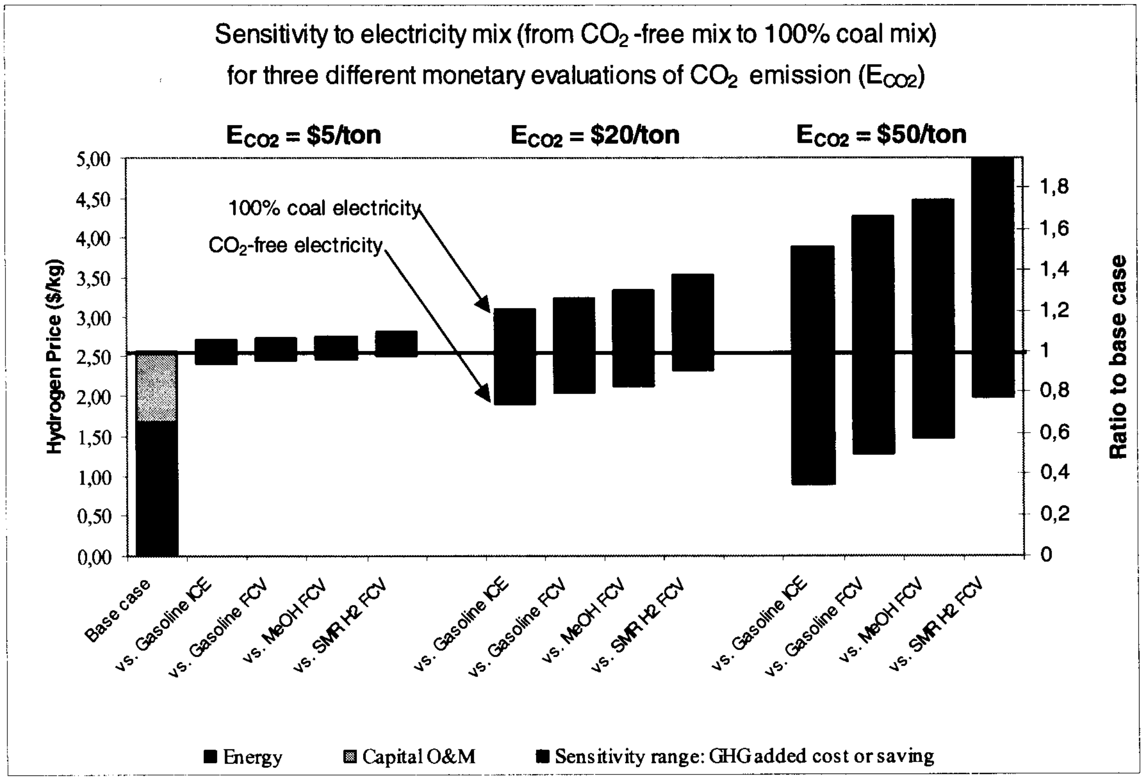


Figure 4.7: Sensitivity of hydrogen price to parameters affecting the GHG cost/saving component (C_{GHG}).

Looking at figure 4.7, each "black bar" represents the range of added cost (surtax) — above the base case line — or saving (credit) — below the base case line — corresponding to the range of electricity mix. A surtax is calculated when the life-cycle GHG emissions of the electrolytic hydrogen option are higher than the fuel option to which it is compared. Conversely, a credit is calculated when the life-cycle GHG emissions are lower than the fuel option to which it is compared The upper and lower bounds of each "black bar" correspond respectively to hydrogen produced from 100% coal-generated electricity, and from CO_2-free electricity.

The magnitude of the sensitivity range is proportional to the monetary valuation of CO_2 (E_{CO2}); so for a given value of E_{CO2}, the sensitivity range is constant regardless of the fuel option to which electrolytic hydrogen is compared. In figure 4.7, the sensitivity range for each of the three CO_2 monetary valuations of $5/ton, $20/ton and $50/ton corresponds respectively to 12%, 48% and 117% of the base case price of hydrogen.

However, the "breakeven point" between a surtax and a credit shifts progressively as the GHG emissions of the reference fuel option become lower. For instance, when electrolytic hydrogen is compared to the gasoline ICE option, a significant portion of the electricity mix range results in a credit for electrolytic hydrogen (portion of the sensitivity range bar below the base case hydrogen price line). But when compared to the SMR option, most electricity mix would result in a surtax (portion of the sensitivity range bar above the base case line).

The cost model gives the possibility to compare electrolytic hydrogen with four other reference fuel options, but not explicitly with "hybrid" cars. From a fuel comparison perspective, hybrid cars can be treated as a sub-case of the gasoline ICE option, with an improved fuel economy. The magnitude of this improvement can be estimated from commercially available cars offering both the standard ICE option and the hybrid option, like the Honda Civic. Based on the fuel economy data for both options [77], a fuel economy improvement in the order of 25-30% can be expected. As a result, GHG emissions are approximately equivalent to those of the gasoline FCV option. So with respect to the "GHG added cost/saving" component, the hybrid case is thus equivalent to the gasoline FCV option in figure 4.7.

The electricity mix and monetary valuation of CO_2 emissions are discussed further in the second part of the analysis, along with other issues (not related to GHGs) affecting the comparative aspect of electrolytic hydrogen.

4.4 Analysis from Three Perspectives

Using the results of the parametric study as a quantitative support, it is now possible to discuss and contrast the influence of the various issues from a technical, economic and comparative perspective. Metaphorically, these three perspectives could be seen respectively as those of an engineer, a businessman and a policymaker (figure 4.8). Each profession archetype sees some potential benefits in an electrolytic hydrogen fuel infrastructure, but needs a common ground to discuss the relative importance of the various issues and to get feedback from the other two. The cost model can provide such a common ground.

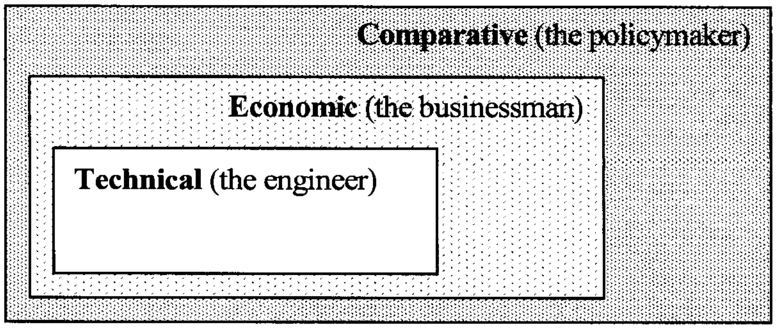


Figure 4.8: Perspectives considered in the second part of the analysis.

This section attempts to translate the results from the parametric study into "issues" that affect the competitive position of electrolytic hydrogen as a fuel. The dominant issues in each perspective are discussed, as well as the effect of the range values used for sensitivity analysis.

First, each of the parameters for which a sensitivity range has been calculated in the previous section is mapped in a two-dimensional (2-D) space, with the hydrogen price sensitivity on one axis and the dominant aspect(s) influenced on the other (technical, economic, comparative). The sensitivity is expressed in percent of the base case hydrogen price, and categorized in three levels: low (0-20%), medium (20-60%) and high (> 60%). See figure 4.9.

Three elements of caution need to be pointed out in interpreting the results of figure 4.9. One is that the sensitivity level of a given parameter is directly related to the range of values chosen for the sensitivity analysis. Although the ranges selected in the study are believed to be representative of the manoeuvring room available through plausible technical improvements, market conditions or policy measures, they introduce a subjective element in the analysis. For example, the sensitivity of the hydrogen price to the electrolyzer unit cost (e_u) is based on a range of 100-1000 $\$/kW_e$, but a narrower range would lower the position of this parameter on the sensitivity axis. One way around this problem would be to specify a uniform range of variation for each parameter (a uniform percentage above and below base case value). However, this option is hardly applicable here because some parameters can only vary by a few percent in an actual electrolyzer station, whereas others can vary by orders of magnitude (e.g. electrolysis pressure), and yet others (like GHG added cost/saving) are not even considered in the base case.

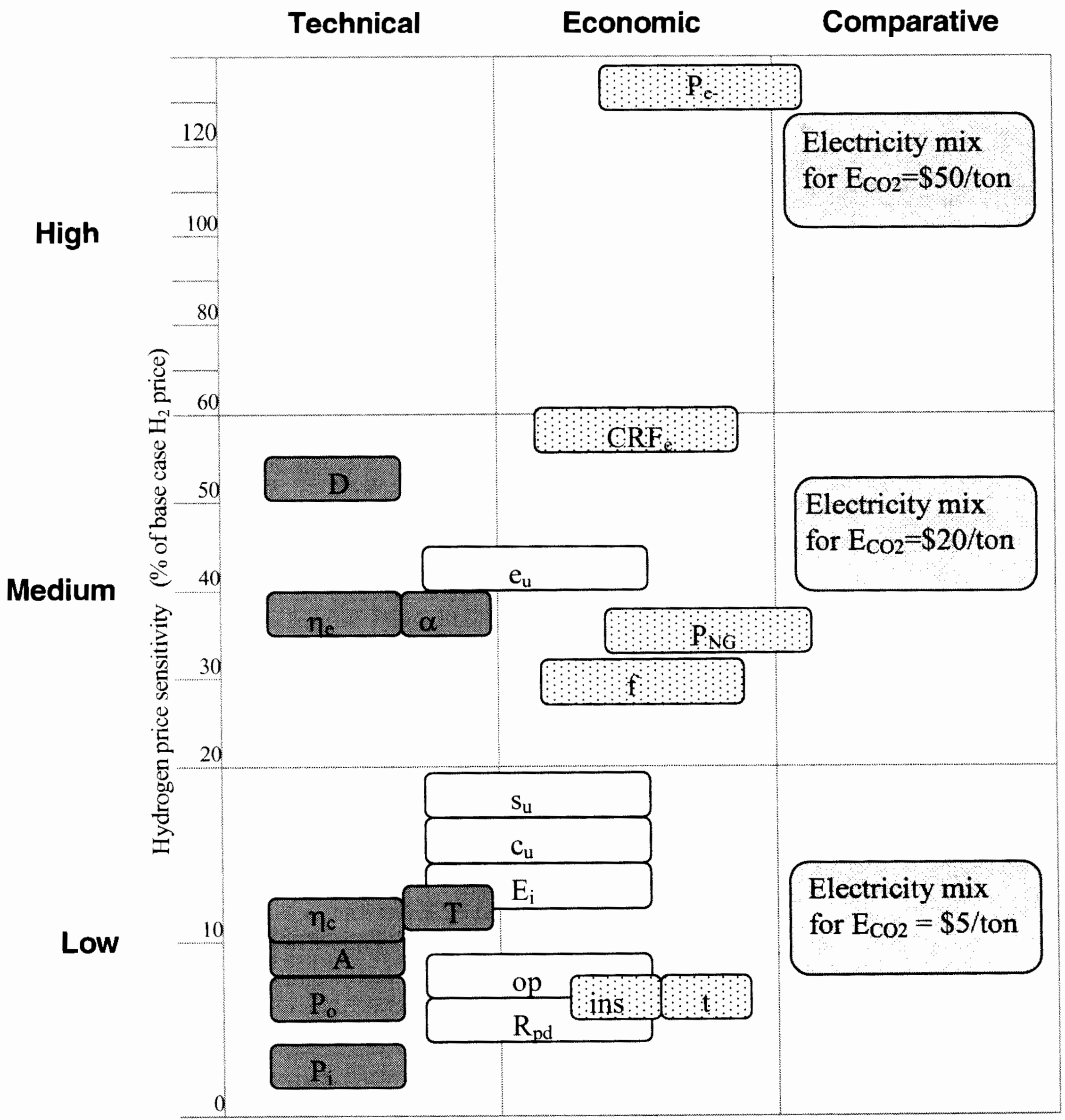


Figure 4.9: Mapping of parameters in terms of hydrogen price sensitivity and aspects influenced.

The second point to keep in mind is that the parametric sensitivity levels in figure 4.9 reflect the assumptions contained in the model. For example, the effect of electrolysis temperature (T) may be underestimated, as the model assumes that all the required energy comes from electricity, even though a cheaper heat source could provide a sensible portion of the energy at high temperature.

Finally, the items found in the "comparative" column only reflect the GHG portion of the comparative aspect. They do not include the effects of other existing fuel taxes or possible fuel economy improvements for instance. The only two parameters in the comparative column at this point are the electricity mix and the monetary valuation of CO_2 (E_{CO2}), which are presented together since they are coupled in the calculation of the "GHG added cost or saving". The parameter "electricity mix" appears at three different positions in figure 4.9 to show how the sensitivity of hydrogen price to the electricity mix increases proportionally to the monetary valuation of CO_2.

Notwithstanding these limitations, figure 4.9 provides useful indications about the relative impact of various issues on the price of electrolytic hydrogen. To translate the impact of parameters affecting the price of electrolytic hydrogen into "issues", the parameters of figure 4.9 were linked to one or more corresponding issue(s). The result is a list of fifteen distinct issues listed in table 4.5 below, with their dominant aspect (T-technical, E-economic, C-comparative). The first nine correspond closely to the issues pointed out in the first part of the analysis as deserving further attention.

Issue		**Associated Parameters**	**Dominant aspect**		
			T	**E**	**C**
1	Financing scheme & economic parameters	CRF_e (& related parameters)		X	
2	Hydrogen storage	D, s_u, A	X		
3	Volume manufactured	e_u, c_u, s_u		X	
4	Capacity factor	f		X	
5	Electricity price	P_{e^-}		X	
6	Electrolyzer efficiency	η_e	X		
7	Use of natural gas	α, P_{NG}	X		
8	CO_2 monetary valuation	E_{CO2}			X
9	Electricity mix	"electricity mix"			X
10	Compression	η_c, c_u	X		
11	O&M and extraordinary expenses	op, E_i	X		
12	Electrolyzer materials	e_u	X		
13	Operating conditions	T, P_i, P_o	X		
14	Insurance and property taxes	ins, t		X	
15	Size of electrolytic hydrogen station	V, D, R_{pd}, P_{e^-}	X	X	

Table 4.5: List of "issues" associated with the parameters used in the cost model.

These fifteen issues are then mapped in figure 4.10, in a 2-D space similar to the one used for the parametric sensitivity analysis (figure 4.9). The potential impact (high, medium or low) of each issue corresponds to the sensitivity found for the associated parameter(s) in figure 4.9. When more than one parameter is linked to an issue, the sensitivity of hydrogen price to that particular issue reflects the compounded sensitivity to the related parameters.

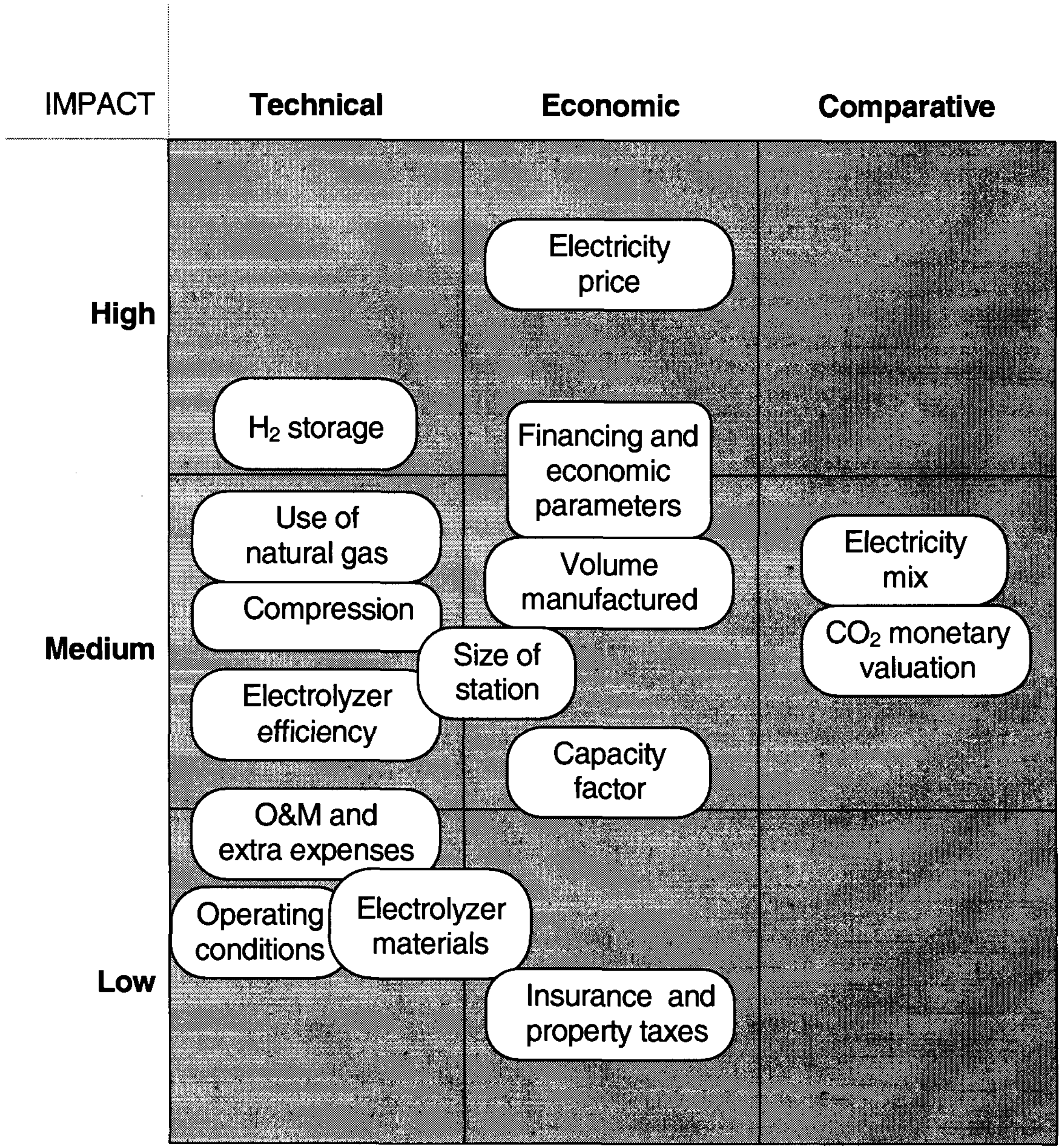


Figure 4.10: Distribution of issues affecting the price of hydrogen from decentralized electrolysis.

For the electricity mix and CO_2 monetary valuation, the case E_{CO2} = \$20/ton is selected to reflect the most likely upper limit of market value for CO_2 emissions, based on actual transactions and projected prices in this emerging market [20]. This is a reasonable value ascribed to a compliance cost for emission reduction. It should be noted though that this is, at best, only a lower bound for the true marginal external cost of CO_2 emissions.

Based on the results of figure 4.10, the issues with the most impact on the competitive position of electrolytic hydrogen are briefly discussed in the following three subsections, while others are simply touched on, considering the limited scope of this analysis.

4.4.1 Influences from a Technical Perspective

4.4.1.1 Hydrogen Storage

Surprisingly, the technical issue that ranks highest in figure 4.10 is *hydrogen storage*. There are a few reasons explaining why hydrogen storage has more impact than any other technical issue in this analysis. First, the study only considered electrolyzer stations offering the same convenience of fast refuelling as gasoline. This implies that sufficient quantities of hydrogen have to be stored at the fuelling station site to support a "fast fill" mode. Second, only the high-pressure gaseous hydrogen storage option was considered here, with its associated technical and economic limitations.

In this analysis, the storage requirements are determined by the quantity deemed sufficient to provide "fast fill" convenience for a given station size, and by the fraction of stored hydrogen which is available in practice. The former is expressed in the model by the parameter D, in equivalent days of nominal production, and the latter by the parameter A, giving the available fraction of hydrogen stored.

The selected range of values for the parameter D in the sensitivity analysis is 2-11.4, reflecting some assumptions made in the DTI report for hydrogen storage requirements as a function of station size [43]. The maximum range value $D = 11.4$ corresponds to the smallest electrolyzer station considered in this study, i.e. a personal appliance supporting the hydrogen needs of two FCVs. This value is obtained by assuming two FCV tanks' worth of usable hydrogen storage. In other words, it would take 11.4 days at the nominal hydrogen production rate (determined by average daily consumption) to produce enough hydrogen to fill completely the hydrogen tanks of two FCVs.

As the station size increases though, the refuelling station need not store enough hydrogen to fill all the FCVs it supports. For instance, a station supporting 100 FCVs need only provide enough storage for one day's worth of production, plus a reserve for unexpected failures or unusual surges in demand. In this case, the minimum range value D = 2 is considered reasonable, as it can accommodate a full day's shutdown. So the size of the electrolyzer station has a significant impact on the storage requirements, for the "fast fill" mode.

Figure 4.11 shows quantitatively the increase in capital cost due the to higher storage requirements of a very small station. Both cost distributions in this figure are calculated using the same base case values for the specific capital cost of the electrolyzer, compressor and storage. The O&M costs are kept equal for the purpose of comparison, even though they represent a smaller percentage of total capital cost in the personal appliance case (because of the large increase in storage capital cost). The electrolyzer and compressor capital costs are slightly higher in the personal appliance case because of a larger surge factor, but the capital cost increase comes overwhelmingly from the storage component. In the personal appliance case, the specific storage capital cost is about triple the combined capital cost of the electrolyzer and compressor, and it accounts for nearly 40 % of the total hydrogen price.

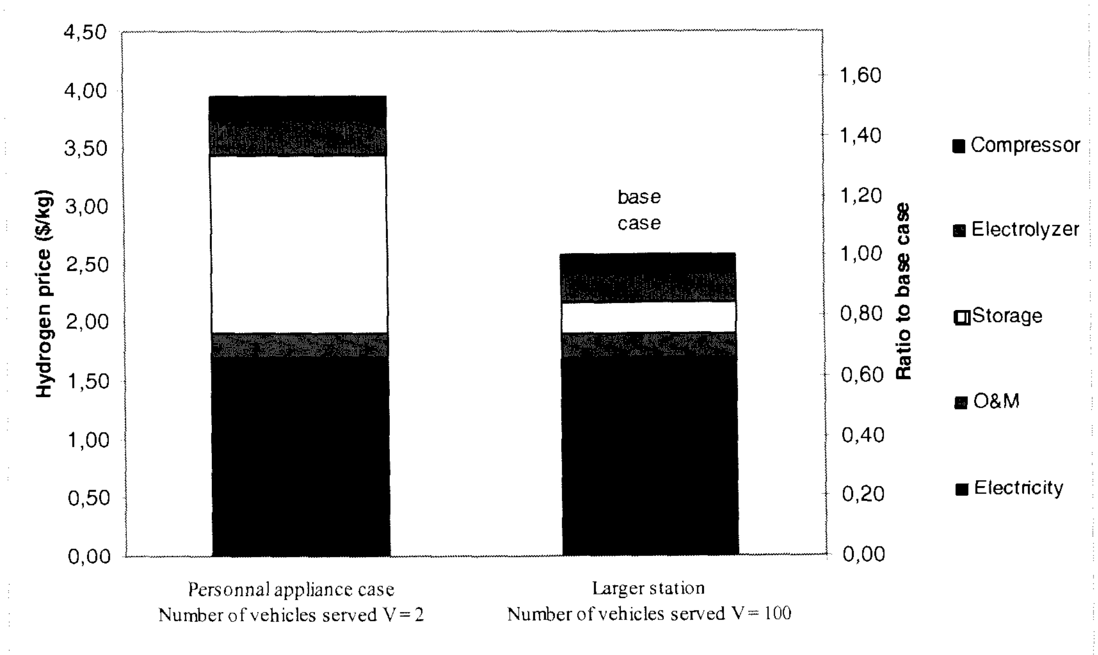


Figure 4.11: Impact of hydrogen storage requirements for personal appliance case (2 FCVs, D = 11.4) and larger station (base case: 100 FCVs, D = 2).

The Electrolyser report avoided the large capital cost associated with storage for the personal appliance case, by considering only the "time fill" option, i.e. hydrogen stored directly onboard the FCV as it is produced. This analysis did not consider the "time fill" option, because it increases the refuelling time significantly and can limit the driving range. These limitations are accentuated for a small station. With the "time fill" option, a FCV fuelled by a personal appliance could not travel a long distance two days in a row, because the electrolyzer would then take a few days to produce enough hydrogen to fill the tank again.

One disadvantage of compressed hydrogen storage is that a significant portion of the hydrogen always remains in the storage tanks, because pressure in the station storage vessels goes down while it increases in the FCV tanks during transfer of hydrogen. Thomas et al. suggest that hydrogen should be dispersed in at least three separate refueling tanks to provide cascade filling of the FCV tank; i.e. the vehicle tank would be filled first from the lowest-pressure storage vessel, moving in succession to the highest-pressure vessel to assure maximum mass flow and minimum compression energy. But even with multiple tanks and cascade filling of the FCV, at best 60% of the stored hydrogen can be utilized [43]. That is why the base case assumed only 50% of the stored hydrogen is usable (parameter $A = 0.5$). The net effect is that the storage volume needs to be twice the size (and cost) of what is really required in terms of stored hydrogen. Private discussions with a company active in the design of hydrogen refuelling stations indicated that the fraction of usable hydrogen could be increased up to the 90% level by clever cascading of tanks and the use of a small compressor.

The high specific capital cost of compressed hydrogen storage (parameter s_u) accentuates the effects of storage requirements discussed above. Indeed, compressed-gas storage is rather expensive, particularly when compared to storage for liquid fuels like gasoline. Various sources in the literature provide useful estimates for the capital cost of high-pressure storage tanks (350-400 bars). They are generally in the range of 300-500 \$/kg H_2, but can go over 1000 \$/kg H_2 [28, 29, 43]. For the sensitivity analysis, a relatively optimistic base case value of 200 \$/kg H_2 was used. This value lies somewhere between the projected value used in the DTI report (132 \$/kg) [43] for advanced carbon fiber tanks, and the value used in the Electrolyser report (357 \$/kg) based on commercially available tanks [42].

Some of the assumptions regarding hydrogen storage may have emphasized its impact on the price of hydrogen; nevertheless the analysis stresses the importance of this issue in planning a hydrogen fuelling infrastructure for FCVs. Based on these results, here are four possible avenues to restrain the impact of storage:

- Eliminate stationary hydrogen storage by making the "time fill" option acceptable. One particularly ambitious approach is to have a small electrolyzer directly onboard FCVs, to produce hydrogen wherever the FCV can be connected to the electric grid, provided there exists a convenient way to bill this electricity to the user.
- Favor electrolyzer stations that support a larger fleet of FCVs, to minimize the storage requirements. (Minimize parameter D)
- Use a compressor to optimize the fraction of usable stored hydrogen. (parameter A). This compressor could be the same as the one used for compressing hydrogen in the first place.
- Develop inexpensive hydrogen storage technology.

4.4.1.2 Electrolyzer

The sensitivity analysis suggests that the *electrolyzer efficiency* (η_e) is the issue that has the most impact among those directly related to the electrolyzer. That is because the amount of electricity required (which is the dominant cost in electrolytic hydrogen) is directly related to the energy efficiency of the electrolyzer. Also, the more efficient an electrolyzer is, the smaller it has to be to deliver a given flow rate of hydrogen.

The actual impact of electrolyzer efficiency could be less than suggested in the sensitivity analysis however. First because most electrolytic cells commercially available today can already operate at a relatively high energy efficiency (80-90% HHV), so the available room there is limited. Also, for the purpose of the sensitivity analysis, the model assumes a constant specific capital cost of electrolyzer ($/kW) regardless of efficiency, with the net result that a more efficient electrolyzer is smaller and proportionally less expensive. In reality, an improved energy efficiency would likely imply a higher specific capital cost of electrolyzer, offsetting the cost reduction, partially or completely.

One surprising result of the sensitivity analysis is the low impact of *operating conditions*, such as the temperature and pressure at which water electrolysis takes place. Their impact on the price of electrolytic hydrogen may have been minimized here because of some assumptions contained in the model, yet the results suggest that an optimization of operating conditions would have only a limited effect on the price of electrolytic hydrogen.

With respect to temperature, the model focused on the resulting energy requirements based on thermodynamic considerations only, but it did not consider explicitly some indirect potential benefits. For instance, it does not reflect efficiency improvements associated with higher operating temperature, nor does it consider the full benefits of high temperature electrolysis (HTE). Because all the required energy (even heat) is assumed to come from electricity in the sensitivity analysis, the net effect on the energy component of the hydrogen cost is very small. In principle though, the use of free heat in HTE could cut the energy cost of water electrolysis by up to 25%, as pointed out in Chapter 2.

The effects of electrolysis pressure may also have been minimized in the analysis because of some assumptions contained in the model. In terms of capital costs, the model does not explicitly consider an increased electrolyser cost (e_u) with higher operating pressure, nor does it consider a lower compressor capital cost (c_u), since the compressor unit cost is based on the hydrogen flow and not the degree of compression. In terms of energy, the model does not consider any increase in efficiency with higher pressure, and it assumes a constant value of 100% for current efficiency. This is a valid approximation at low pressure, but the current efficiency tends to decrease at higher operating pressure.

The specific capital cost of the electrolyzer per kW_e (e_u) is influenced more by the volume manufactured (primarily an economic issue) than by the materials used in the electrolytic cells. So even if the cost of electrolytic cells were reduced by half or more, by using inexpensive materials, the overall impact on hydrogen cost would be only a few percents. A review of the cost distribution for various electrolyzer station sizes in the Electrolyser report [42] indicates that simplification and cost reduction in the power and water conditioning systems could have a comparable impact on the capital cost of the electrolyzer.

The issue of *O&M and extraordinary expenses* has not been addressed with much detail, due to its relatively low impact in the sensitivity analysis. However some items are worth pointing out. From the estimates found in the Electrolyser report, 60-90% of the O&M costs are related to the compressor and water purifier components. Also, O&M annual costs generally represent a larger percentage (up to 5-7%) of the capital costs for smaller electrolyzer stations.

4.4.1.3 Compression

Figure 4.10 shows that the *compression* issue has only a moderate impact on the price of hydrogen. This impact reflects the combined sensitivity of hydrogen price to the capital cost of the compressor (c_u) and the energy efficiency of compression (η_c). Some couplings are not explicitly reflected in the model, such as higher O&M costs and a likely higher specific capital cost (\$/kW$_{out}$ HHV) associated with more intensive compression. But the range values used in the sensitivity analysis are believed to cover these simplifications.

The maximum value considered for the output pressure from the compressor (P_o) was limited at 414 bars (6000 psi) because it appeared to be a practical limit for commercial applications of hydrogen storage. However, recent work on hydrogen storage for FCVs is pushing this limit towards 700 bars (10000 psi). If this were to become commercially viable, the compression issue could have a slightly higher impact on the hydrogen price. At this pressure level, hydrogen can no longer be approximated as an ideal gas (like it is the case in the cost model), so the model would underestimate the energy use related to compression. The trade-offs between electrolysis pressure and compression are discussed in Chapter 2.

4.4.1.4 Use of Natural Gas

The sensitivity analysis confirmed that natural gas assisted steam electrolysis (NGASE) could be a promising avenue for reducing the cost of electrolytic hydrogen. However, given the trend of intensive developments in small-scale SMR, it is unlikely that NGASE will reach the commercial stage. That is because small-scale SMR promises similar or higher performance in terms of energy efficiency (up to 80% HHV) [29], and it is already the focus of much development for processing the natural gas used in stationary fuel cell systems. The main advantage of NGASE vs. small-scale SMR would be the ability to use both electricity and natural gas. The principles of NGASE are summarized in section 2.3.1.

4.4.2 Influences from an Economic Perspective

4.4.2.1 Electricity Price and Capacity Factor

Predictably, the sensitivity analysis shows that *electricity price* is the issue to which electrolytic hydrogen is most sensitive. This was expected considering that electricity remains the dominant cost of electrolytic hydrogen, typically 50-80% of its total cost. Several other parametric studies done on the cost of electrolytic hydrogen also stress the major impact of electricity prices [40, 51, 55].

The influence of electricity prices stands out when compared to the room available from technical improvements in the electrolyzer station. Figure 4.12 shows how important the impact of electricity price is, compared to a combination of all the best case values from the technical perspective. It shows the price of electrolytic hydrogen as a function of electricity price, keeping all the other base case values constant. Only the second vertical bar in figure 4.12 uses the best case values of technical parameters, at the base case electricity price of 3¢/kWh. Table 4.6 gives the best case values (ideal technology) used to calculate the second vertical bar in figure 4.12.

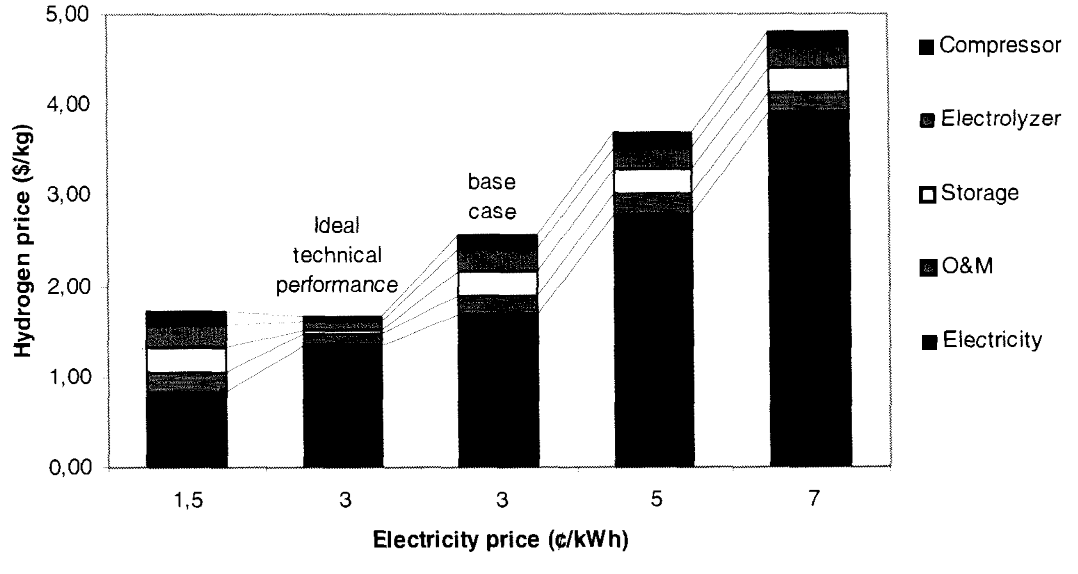


Figure 4.12: Relative impact of electricity price vs. ideal technical improvements (Ideal technical performance) for the base case.

Parameter		Units	Ideal technology	Base case	Improvement
e_u	Electrolyzer unit cost	$\$/kW_e$	100	200	-50%
c_u	Compressor and dispenser unit cost	$\$/kW_{out}$ – HHV	70	170	-59%
s_u	Hydrogen storage unit cost	$\$/kg H_2$ storage capacity	50	200	-75%
A	Available fraction of stored hydrogen		1	0.5	+100%
op	Operation and maintenance	% of C_{cap}	0.5	2	-75%
η_e	Energy efficiency of electrolyzer	%	100	80	+25%
η_c	Compressor efficiency	%	100	75	+33%

Table 4.6: Values used to estimate the maximum cost reduction achievable through technical improvements.

In the base case cost distribution of electrolytic hydrogen (third vertical bar of figure 4.12) electricity at 3 ¢/kWh represents 65% of the total cost. A convenient way to highlight the importance of electricity price is to express the remaining 35% (capital and O&M costs) in terms of electricity price. For the base case values, this would be equivalent to 1.6 ¢/kWh for capital and O&M costs. So the total price of electrolytic hydrogen can be thought of in general as proportional to the electricity price plus 1-3 ¢/kWh for capital and O&M costs.

The main challenge for electrolytic hydrogen is therefore to identify strategies that minimize the electricity price. A general understanding of the electricity market's dynamics is helpful to see how water electrolysis can take advantage of it. Electric utilities must supply very reliable electricity under widely fluctuating load conditions. For example, the average ratio of minimum hourly demand to peak demand on a daily basis is in the order of 40-50% for American utilities [43]. A consistent large gap between peak load and night-time load characterizes the demand pattern of most utilities. To ensure system reliability, North American utilities must follow strict guidelines, requiring them to maintain different operating reserves, including a spinning reserve accessible instantaneously and a non-spinning reserve accessible within ten minutes.

The "load characteristics" of the electrolysis process put it in an excellent position to take advantage of the mismatch between electricity supply and demand. Unlike many other industrial loads, water electrolysis can be interrupted and operated intermittently without upsetting the basic hydrogen production process. Also, the process does not require high quality power. These characteristics offer the prospect of a large-scale integration of electricity generation and hydrogen production. Utilities could manage distributed electrolyzers as a "recallable" load, i.e. a power supply which can be interrupted when needed. In fact, the process could even qualify as a non-spinning operating reserve for utilities [42]. This type of approach allowing utilities to manage the time at which they provide electricity to electrolyzers, would favor very low cost electricity.

Because of hydrogen storage, electrolyzers can maximize the use of inexpensive excess electricity during off-peak periods. Off-peak electricity represents a key opportunity for low-cost electricity in many locations. This is particularly true for utilities largely dependent on coal or nuclear power generation, because it is often less costly in these cases to let the generator run in off-peak periods than to turn off the process. Based on a survey of American electric utilities, Thomas and Kuhn found out that most utilities have a marginal operating cost (the cost of fuel and other maintenance costs associated with adding extra electrical output at any instant of time) that is consistently below 2 ¢/kWh during night time [43]. It is therefore reasonable to conclude that many utilities could still recover some of their capital investments by providing electricity around 3¢/kWh during off-peak periods.

Due to its high impact on the price of electrolytic hydrogen, off-peak electricity can be the determinant element for selecting the capacity factor of the electrolyzer. That is why the *capacity factor* issue is discussed along with electricity price in this section. For example, an electrolyzer designed to operate 16 hours a day on average will have a capacity factor of 0.67 (16h/24h), but an electrolyzer designed to take advantage of off-peak electricity rates may be designed to operate only 8 hours a day with a corresponding capacity factor of 0.33 (8h/24h). In the latter case, the electrolyzer would have to be designed twice as big to accommodate double the hydrogen production rate. In the sensitivity analysis, the net result is a doubling of the capital cost of the electrolyzer and compressor (but not storage). Doubling the capital cost of these two items in the base case is equivalent to increasing the electricity price by 0.7¢/kWh. So if the average electricity price goes down by at least 0.7¢/kWh by using off-peak rates only, it is then worth it to increase the capital cost of the electrolyzer. This kind of trade-off must be considered when selecting the capacity factor of an electrolyzer station.

Electrolytic hydrogen from renewable energy sources (hydro, wind, solar...) is the long-term objective to minimize GHG emissions and other polluting emissions. Among the renewable options, only hydroelectricity can compete economically today with other large-scale power generation methods. But a very limited number of regions around the world (e.g. British Columbia) have access to abundant inexpensive hydroelectricity. There are also few incentives for utilities to sell off-peak electricity from hydro power, since dams can be controlled to store water for peak demand periods and exports. Nevertheless, some utilities like BC Hydro are working on a development strategy to provide decentralized electrolytic hydrogen, based on time-of-use electricity at prices as low as 2.4 ¢/kWh (3.1 ¢/kWh CAN) [78]. Wind energy also presents some interesting potential in the short to mid-term, particularly if some credits are granted to encourage its development. An example is the special credit of 1.2¢/kWh for wind energy available in Canada since 2001.

So to summarize, here are some avenues to increase access to low-cost electricity:

- Optimize access to off-peak electricity by establishing new better adapted tariff structures for off-peak electricity.
- Take advantage of the interruptible nature of water electrolysis to use existing operating reserves at low rates, with limited additional GHG emissions. Spinning reserves in North America amount to approximately 15 GW (2% of the potential generating capacity), which represents enough electricity to produce 2.3 million tons of electrolytic hydrogen annually, or enough hydrogen to fuel over 10 million FCVs [42].
- Offer fiscal incentives for hydrogen produced from electricity with low GHG emissions.

4.4.2.2 Financing Scheme and Economic Parameters

In the cost model, the total installed capital cost of an electrolyzer station is calculated independently of the way it is financed. But the actual annual expense associated with this capital cost depends on the effective capital recovery factor (*CRFe*), which incorporates the effects of all economic parameters that influence the financing. The *CRFe* acts as a multiplying factor of the totalled installed capital cost to determine the actual annual cost of the capital assets. For example, a *CRFe* = 0.15 means that the annual expense attributed to capital cost corresponds to 15% of the total installed capital cost.

As explained in the cost model description, three financing scenarios were envisioned: financed by the consumer as a home mortgage (applicable to very small stations only), by a business, and by a utility. A base case was developed for each of these financing scenarios (Table 4.7) and a sensitivity analysis performed on the relevant parameters to see how the *CRFe* is affected (Figure 4.13). The base case values are nearly all identical to those used by Thomas and Kuhn [43]. The *CRFe* base case value of 0.1230 used throughout this study corresponds to the "utility base case" below.

Parameter		**Units**	**Range considered**	**Base case**
N	Economic recovery period	years	5 – 30	**15**
If treated as a personal appliance (financed by home owner - base case H)				
i_m	Mortgage interest rate	%	5 – 15	H: 9
T_p	Personal tax rate of owner	%	25 – 50	H: 35
If treated as a business investment (financed by company - base case B - or utility - U)				
i	General inflation rate	%	0 – 15	B: 2.7 U: **2.7**
r	After-tax real rate of return on investment	%	4 – 15	B: 10 U: **6**
T_b	Business tax rate	%	0 – 50	B: 26 U: **0**

Table 4.7: Parameters affecting the effective capital recovery factor (CRF_e)

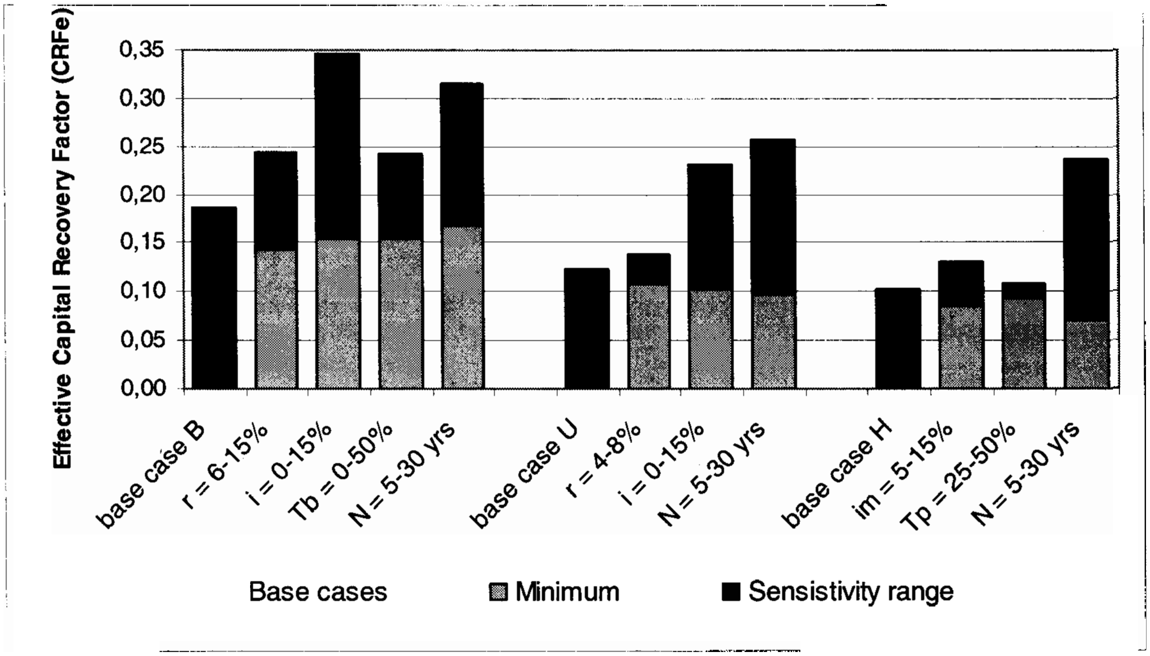


Figure 4.13: Sensitivity of the effective capital recovery factor (CRF_e) to various economic parameters under three different financing scenarios (B: business, U: utility, H: home mortgage)

The most important result of figure 4.13 is that the value of *CRFe* can vary by as much as a factor of three (from less than 0.10 to over 0.30). In other words, the portion of hydrogen price that covers the electrolyzer station's capital cost can vary by a factor of three, simply on the basis of the financing scheme and economic parameters.

Looking at the main sensitivity results of figure 4.13, the economic recovery period (*N*) has a relatively high impact, but extending its value beyond the base case value of 15 years has very little effect. The rate of return on investment (*r*) has more impact in the "business" scenario than the "utility" scenario because the expected rate of return would likely be lower for a utility. That assumption is justified essentially by the fact that the opportunity for a utility lies more in additional sales of electricity than the electrolyzer station itself, which is not the case for the "business" scenario. Finally, the impact of inflation in the "business" and "utility" scenarios highlight the importance of stable economic conditions to minimize the capital cost.

Figure 4.13 indicates that the "home owner" financing scenario could be the least expensive (*CRFe* = 0.1020 for base case "H") followed closely by the "utility" scenario (*CRFe* = 0.1230 for base case "U"). However, since the "home owner" scenario applies only to very small electrolyzer stations with higher storage requirements, the "utility" scenario may turn out to be the most advantageous one as suggested in figure 4.14.

So having electrolyzer stations financed by a power utility appears to be the best scenario for at least three reasons.

- Utilities can afford a lower expected rate of return on the electrolyzer stations, because their main financial interest comes from additional sales of electricity, which constitutes their core business. Also, utilities themselves generally have access to low-cost financing.
- Utilities could offer the flexibility that is necessary to adapt to an evolving market for electrolytic hydrogen. As the demand increases, a utility could replace small electrolyzers by larger ones and move the smaller ones to locations with lower demand. Electrolyzer stations of proper capacity would then be amortized over their full economic life.
- The capital cost of multiple electrolyzer stations could then be averaged, the most profitable stations compensating for the ones with a low utilization.

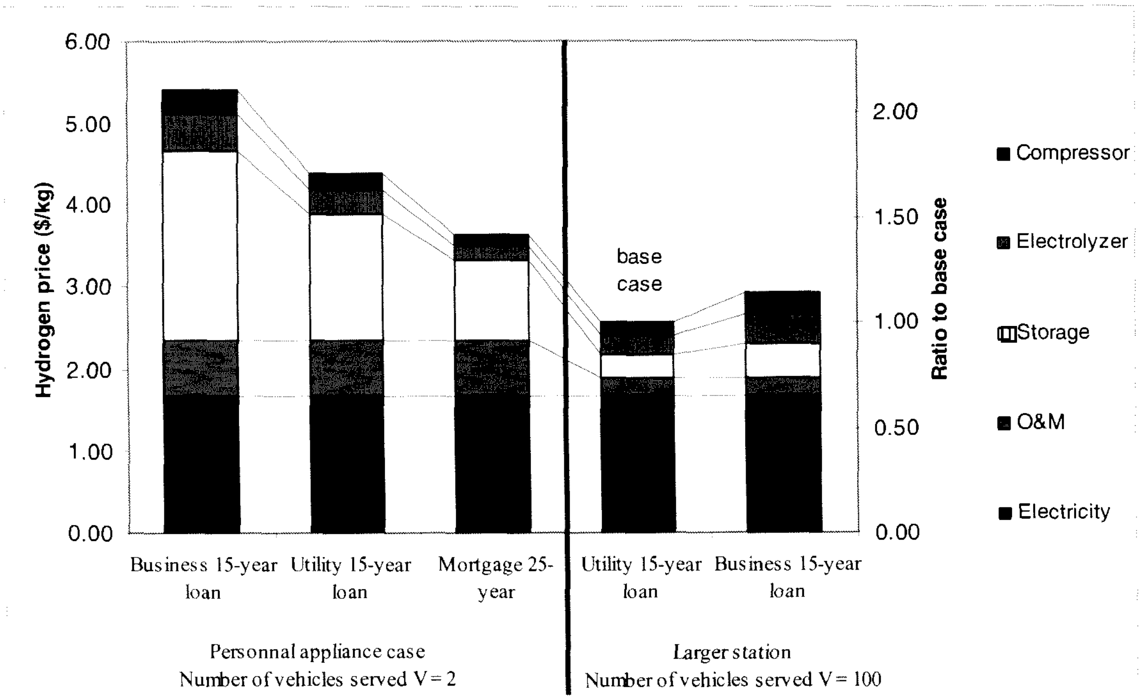
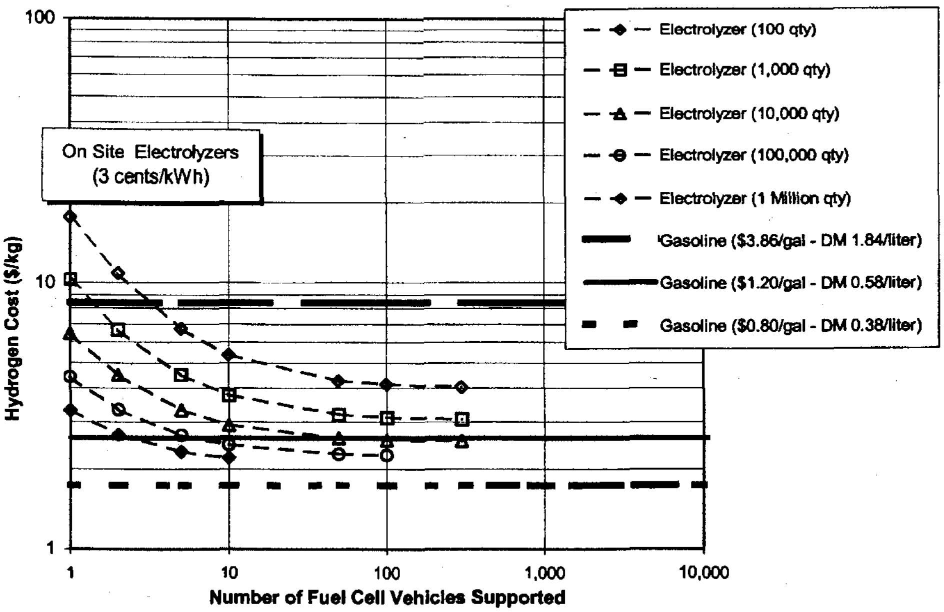


Figure 4.14: Impact of financing scenario on hydrogen price for two different sizes of electrolyzer stations. The unit capital cost of electrolyzer, compressor and storage components are the same for the two sizes. O&M represents the same % of capital cost for each electrolyzer station's size.

4.4.2.3 Other Economic Issues

Figure 4.10 suggests that the *volume* of electrolyzer stations manufactured is the economic issue with the next most important impact on hydrogen price, after the electricity price and financing scheme. The range values in the sensitivity analysis for the unit cost of the electrolyzer, compressor and storage components (e_u ,c_u and s_u) were estimated without distinguishing between the impact of inexpensive materials, simpler design and larger volume.

However, other studies have looked more specifically at the impact of volume for electrolytic hydrogen fuelling stations, and show an important drop in capital cost with increasing volume [4, 42]. The graph below (figure 4.15) comes from one of these studies. For a station supporting 100 FCVs and an electricity price of 3¢/kWh, both quantities equal to the base case of this study, this graph shows that increasing the volume of electrolyzers from 100 to 1000 units results in a decrease in hydrogen price from approximately 4$/kg to 3$/kg, i.e. about 25% reduction.



Capital Recovery Factor	0.1842
Electrolyzer Capacity Factor	0.5
Fuel Cell Vehicle to Gasoline ICE fuel economy ratio (LHV)	2.2

(Gasoline price lines correspond to the cost of untaxed hydrogen that would yield the same cost per mile driven in a fuel cell vehicle as gasoline cost per mile in a conventional ICEV)

Figure 4.15: Impact of the volume of electrolyzer stations manufactured on the hydrogen cost from a previous study by Thomas et al. [4]

The Electrolyser report gives additional information with respect to the impact of volume on the capital cost of the various components making up the electrolyzer station. It shows that the electrolyzer component is the one that drops most rapidly with volume, followed by the compressor. The storage component experiences only modest cost reductions with volume. Interestingly, some of the cost reductions related to volume could come from the mass production of stationary fuel cell systems, which share many similarities with electrolyzers.

The *size of the fuelling station*, i.e. the number of vehicles it can support, reflects the degree of decentralization of an eventual electrolytic hydrogen fuel infrastructure. In the cost model, changing the number of vehicles supported (parameter *V*) does not modify the price of hydrogen, so other parameters must be adjusted independently. The size has indirect effects on parameters from both the technical and economic perspectives. A smaller station size increases the requirements to deal with statistical variations in demand (daily and seasonal). This is handled primarily by the storage capacity (parameter *D*: equivalent number of days of storage) as discussed earlier in the storage issue, but also partially by the electrolyzer and compressor, based on a higher peak-to-demand ratio (parameter R_{pd}) for smaller stations.

There is no definite relationship between electrolyzer size and electricity price, because it can vary in so many different ways, according to local electricity rate schedules. But residential electricity rates for small applications are generally higher than those for larger industrial applications. So larger electrolyzers could be expected to benefit from lower electricity prices, unless a particular tariff structure is put in place to give equal access to low electricity rates.

Finally, the utilization of the electrolyzer station is another factor that can be linked to its size. In the cost model, the station's size is function of the number of vehicles supported. Accordingly, the capital cost is amortized over the total projected hydrogen production. In reality though, there could be fewer vehicles to support than actually projected. For instance, if a station designed to support 100 FCVs serves only 50 FCVs on average during its initial years, it is utilized only at 50% of its rated production. The capital cost must then be amortized over half the projected production to remain profitable. The net effect is a doubling of the portion of hydrogen price assigned to cover the amortization of the station's capital cost. Thus, even if the capital cost of smaller station appears higher (per unit of hydrogen produced), it could still be more economical to add production capacity as needed, than invest in a larger electrolyzer station that is under-utilized.

4.4.3 Influences from a Comparative Perspective

Thus far, technical and economic issues that directly influence the cost of electrolytic hydrogen have been discussed, but the competitive position of hydrogen also depends on its price relative to other fuel alternatives. An in-depth look at the cost of other fuelling options is clearly outside the scope of this research. However, it is possible to estimate the impact of some indirect issues affecting the competitive position of hydrogen. One such issue that has been addressed already in the sensitivity analysis is the impact of a GHG tax/credit reflecting the combined effect of CO_2 monetary valuation and electricity mix. This GHG tax/credit is further discussed in this section as well as other existing fuel taxes. The effect of potential fuel economy improvements of other fuel options is also considered.

To illustrate concretely the impact of these issues on the competitive position of hydrogen, actual information from three cities was used. These three cities (Vancouver, Los Angeles, and Paris) present fairly different electricity mix, electricity rates and fuel taxes.

4.4.3.1 CO_2 Emissions and Monetary Valuation

One of the objectives of this research was to get a sense of the economic advantage of "clean" electrolytic hydrogen (very low associated CO_2 emissions) versus other fuelling options for FCVs. To estimate this, the cost model calculates the life-cycle GHG emissions (on a per-kilometer basis) associated on the one hand with a FCV using electrolytic hydrogen, and on the other hand with the equivalent vehicle using the alternative fuel option considered. The difference between the two is then assigned an economic value proportional to the monetary valuation of CO_2. If the GHG emissions from electrolytic hydrogen are lower than the alternative option, then the model calculates a theoretical credit for electrolytic hydrogen; if they are higher, the model calculates a theoretical surtax. So both the *electricity mix* and *CO_2 monetary valuation* affect the magnitude of this economic advantage (credit) or disadvantage (surtax) of electrolytic hydrogen versus an alternative fuel option.

Figure 4.16 shows the life-cycle GHG emissions associated with each fuel option considered in the cost model. The calculated GHG emissions are based on a previous study done by the Pembina Institute for Appropriate Development [5]. The GHG emissions associated with electrolytic hydrogen vary widely from 0 to 450 grams of CO2 per kilometer, as a function of the electricity mix.

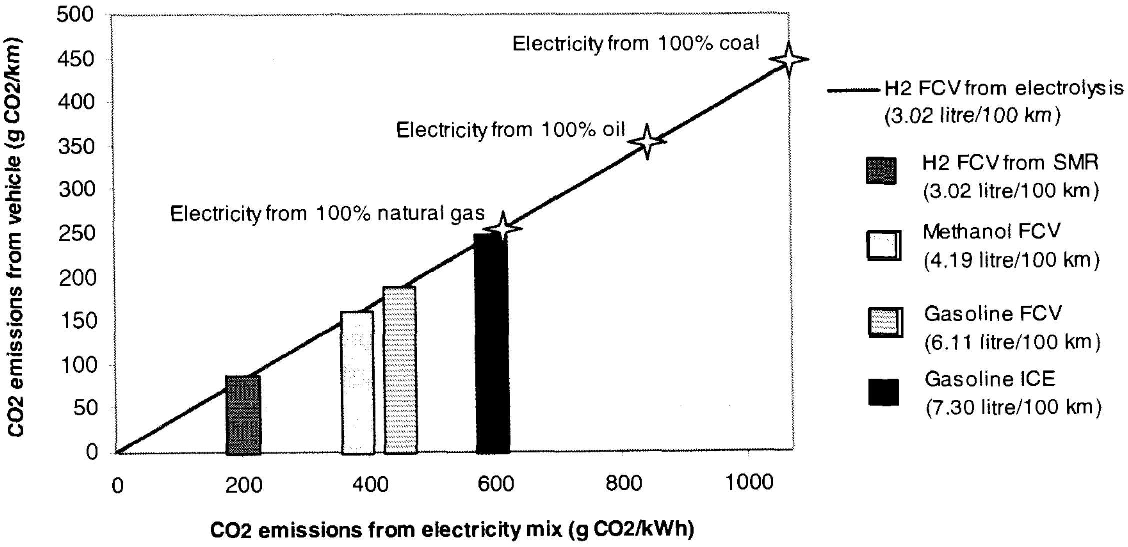


Figure 4.16: Life-cycle CO_2 emissions per kilometer from a FCV using electrolytic hydrogen as a function of electricity mix (solid line), compared to CO_2 emissions of other fuel options.

Figure 4.16 highlights the fact that electrolytic hydrogen produced from fossil fuel-based electricity (coal, oil, or even natural gas) would result in higher life-cycle GHG emissions than any other fuel option considered, despite the better fuel economy of hydrogen-fuelled FCVs. Yet, in many countries most of the electricity comes from fossil fuels. For example, the average electricity mix in the United States produces 650 grams of CO_2/kWh [79]. Hence, a FCV running on electrolytic hydrogen produced from the average electricity mix in the United States would have higher CO_2 emissions than a comparable internal combustion engine (ICE) vehicle running on gasoline.

As indicated by figure 4.16, for water electrolysis to compete with hydrogen from decentralized SMR in terms of GHG emissions, the electricity mix needs to emit less than 205 grams of CO_2/kWh, corresponding to a mix of 35% electricity from natural gas, and the rest from CO_2-free electricity. The use of electricity from spinning reserves could be an exception to the high CO_2 emissions associated with electrolytic hydrogen from fossil-based electricity. That could be justified by the fact that most of the associated CO_2 emissions would be produced regardless, to ensure the reliability of the electricity network.

To foster a shift towards technologies with low associated GHG emissions, a monetary value must be assigned to CO_2; whether it is determined by policy, the market, or a combination of the two. Otherwise, there is no incentive from an economic standpoint to even consider GHG emissions in selecting a fuel option for future FCVs. As seen in the sensitivity graph for the "GHG added cost/saving" (figure 4.7), the monetary valuation of CO_2 can have a sizeable impact on the competitive position of electrolytic hydrogen, if it is high enough. The value $20/ton of CO_2 (equivalent to $73/ton of carbon) was selected to estimate the maximum impact of CO_2 monetary valuation, resulting in a "medium" impact on the competitive position of electrolytic hydrogen (figure 4.10). This value appears to be a realistic upper limit, based on recent price projections for the next decade [20] and actual transactions that have taken place so far in pilot projects.

A useful way to estimate the economic impact of CO_2 monetary valuation is to know that a value of $10/ton of CO_2, applied literally to the range of electricity mix, creates a differential of about 1¢/kWh, in favor of CO_2-free electricity versus coal generated electricity.

4.4.3.2 Comparison of Electrolytic Hydrogen and Gasoline in Three Locations

The cost model developed offers enough flexibility to compare the cost of electrolytic hydrogen and other fuel options in any location. In this concise analysis though, it is obviously impossible to cover all the fuel options in details, let alone a wide array of locations. This is better done in other studies [45]. So the focus of this section has been limited to a comparison between electrolytic hydrogen and gasoline in three cities: Vancouver (Canada), Los Angeles (United States), and Paris (France). These cities were chosen for their different electricity mix, electricity tariffs and fuel taxes, to illustrate the effects of geographic location.

The same base case electrolyser station, designed to serve 100 vehicles and assumed to have the exact same total installed capital cost, is placed in each location. The fuelling cost for the two fuel options in each city is calculated based on an equivalent driving range for the hydrogen FCV and gasoline ICE vehicle. The data used for calculating the fuelling costs is presented in table 4.8 below, with the relevant sources available in Appendix E. The results are shown in figure 4.17.

<table>
<tr><th>Site-specific information</th><th>Vancouver</th><th>Los Angeles</th><th>Paris</th></tr>
<tr><td>* Electricity price (US¢/kWh)</td><td>3.2</td><td>12.8</td><td>5.9</td></tr>
<tr><td>Electricity mix</td><td>Dominated by hydroelectric (93%)</td><td>Dominated by NG (50%) and coal (11%)</td><td>Dominated by nuclear (82%)</td></tr>
<tr><td>† Tax on fuel (US$/GJ)</td><td>5.98</td><td>2.90</td><td>27.23</td></tr>
<tr><td colspan="4">* Electricity prices calculated using local tariff schedule for an electrolyzer station supporting 100 hydrogen FCVs, with a capacity factor of 0.7.
† Hydrogen taxed at same rate as on gasoline, on an energy content basis (HHV).</td></tr>
<tr><td>CO$_2$ monetary valuation</td><td colspan="3">• US$ 20/ton CO$_2$-equivalent
Height of triangle arrows (▼) in figure 4.17 indicates the magnitude of the credit that could be applied to electrolytic hydrogen for reducing GHG emissions compared to gasoline, at US$ 20/ton CO$_2$-equivalent</td></tr>
<tr><td>Vehicle range</td><td colspan="3">• 600 km/full tank on EPA combined driving cycle
(Identical for both the gasoline ICE vehicle and the hydrogen FCV)</td></tr>
<tr><td>Fuel economy</td><td colspan="3">• Gasoline ICE vehicle: 7.30 liter /100 km
• Hydrogen FCV: 3.02 liter /100 km (gasoline equivalent) corresponds to 135 km /kg H$_2$</td></tr>
</table>

Table 4.8: Assumptions and values used for the cost comparison of electrolytic hydrogen with gasoline in three cities.

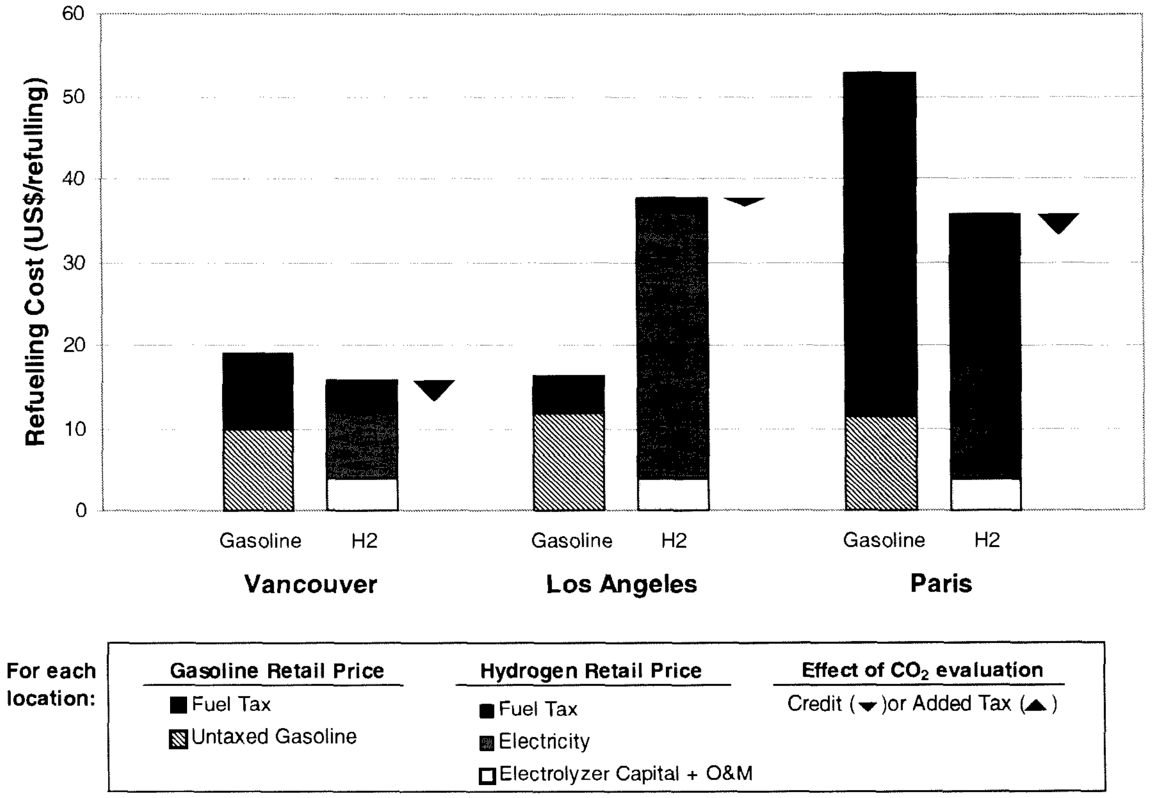


Figure 4.17: Site-specific comparison of gasoline and electrolytic hydrogen retail price including taxes and the effect of credits for low CO_2 emissions.

The first interesting observation is that electrolytic hydrogen would be competitive with gasoline in two of these three locations: Vancouver and Paris, even if it is taxed at the same rate as gasoline. In Vancouver, the low electricity rate is mostly responsible for this result, whereas in Paris it is the high fuel tax that really makes a difference. Notice that even if the electrolyzer capital and O&M costs were doubled in these two locations, electrolytic hydrogen could still compete with gasoline. In Los Angeles though, electrolytic hydrogen would be more than twice as expensive as gasoline, due to a combination of low fuel tax and high electricity rates. Vancouver and Paris, which have lower priced electricity, also happen to be the ones with the lowest GHG emissions. So a CO_2 credit would simply reinforce the competitive position of electrolytic hydrogen in these locations, whereas it would have almost no effect in Los Angeles.

These issues are further discussed in the next three sub-sections, and generalized to see what levels of fuel tax and electricity prices can produce an economic breakeven condition between electrolytic hydrogen for a FCV and gasoline for an ICE vehicle.

4.4.3.2.1 Electricity Price and Mix

As shown in figure 4.17, the average electricity price varies widely from 3.2 ¢/kWh in Vancouver to 12.8 ¢/kWh in Los Angeles. This range of electricity prices is even wider than in the sensitivity analysis (1-7 ¢/kWh), further emphasizing the dominant impact of electricity price on the cost of electrolytic hydrogen. That is because the sensitivity analysis range was oriented more towards inexpensive off-peak electricity.

The electricity price in each of the three cities was calculated using the local rates for the base case electrolyzer size (supporting 100 vehicles) and capacity factor (0.7), i.e. operating 16.8 hours a day. The data used to calculate the electricity price was taken directly from the local utility's appropriate rate schedule (see Appendix E).

A breakeven condition was calculated to estimate the electricity price required for electrolytic hydrogen to compete economically with gasoline. This breakeven condition is defined as an identical fuel cost per kilometer for both fuel options. So the fuel cost per kilometer was calculated in the cost model for a FCV using electrolytic hydrogen (3.02 liter/100 km gasoline equivalent), and an ICE vehicle running on gasoline (7.30 liter/100 km).

The retail cost of untaxed gasoline does not vary much between each of the three locations, so it was estimated at 26 US¢/liter [80] for the purpose of calculating a general breakeven condition. This value corresponds roughly to a crude oil cost of $29/barrel, based on a relationship developed by Thomas and Kuhn [43]. The appropriate fuel tax is then added to determine the retail price of taxed gasoline, for a given location. The price of electricity required to obtain the breakeven condition of electrolytic hydrogen is calculated using the base case capital and O&M costs of the electrolyzer station.

The resulting breakeven condition is presented in figure 4.18 for untaxed electrolytic hydrogen to compete with taxed gasoline. Since electrolytic hydrogen is not taxed, the breakeven electricity price rises rapidly as the tax on gasoline is increased. It ranges from 4.8 ¢/kWh in Los Angeles, to 6.7 ¢/kWh in Vancouver, and a whopping 19.7 ¢/kWh in Paris. Any electricity price below this breakeven level results in electrolytic hydrogen costing less than gasoline on a per-kilometer basis.

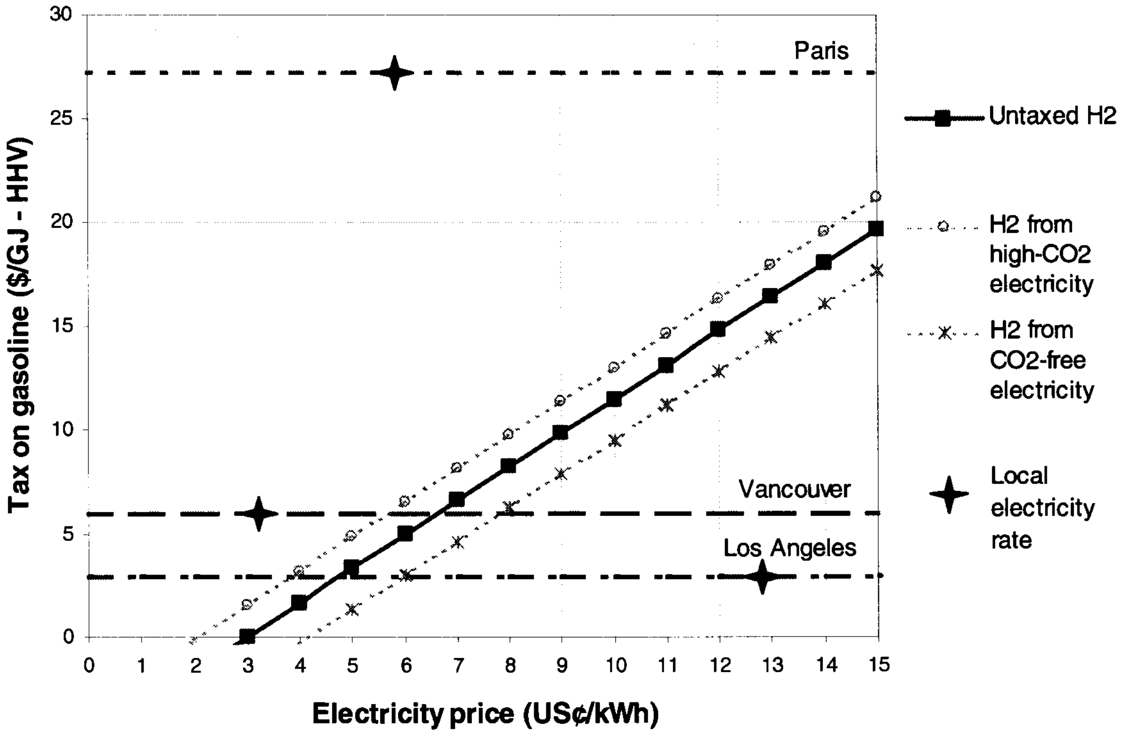


Figure 4.18: Breakeven condition (solid line) for untaxed electrolytic hydrogen to compete with taxed gasoline. Electricity prices to the left of the solid line would result in electrolytic hydrogen being less expensive than gasoline on a per-kilometer basis.

Figure 4.18 also shows the potential impact of the electricity mix, in terms of a credit/surtax for lower/higher GHG emissions from electrolytic hydrogen when compared to gasoline. If the electricity mix results in lower GHG emissions than gasoline, the breakeven condition (solid line) in figure 4.18 is shifted to the right. That is because electrolytic hydrogen can then afford a higher electricity price since it is granted a credit. Conversely, if the electricity mix results in higher GHG emissions than gasoline, the breakeven condition in figure 4.18 is shifted to the left. The dotted lines on each side of the solid line indicate the maximum shift of the breakeven condition based on a monetary valuation of $20/ton of CO_2 and the full range of electricity mix. At $20/ton of CO_2, the electricity mix could shift the breakeven condition over a maximum range of about 2 ¢/kWh.

4.4.3.2.2 Taxes and Credits on Fuels

Similarly to electricity rates, the tax on gasoline varies broadly according to location. At $27/GJ (HHV), the fuel tax in Paris is more than four times higher than in Vancouver ($6/GJ) and about nine times higher than in Los Angeles (less than $3/GJ).

Taxing fuels on an energy content basis creates an incentive for more efficient fuel options. This is highlighted in figure 4.17 where hydrogen is taxed at the same tax rate as gasoline on an energy content basis. In Paris for example, filling up with electrolytic hydrogen turns out to be cheaper than gasoline mainly because of the high taxes on fuels, even though the electricity price is almost double the one in Vancouver. The smaller portion of taxes on electrolytic hydrogen reflects the better fuel economy of the hydrogen FCV (3.02 liter/100 km gasoline equivalent) compared to the gasoline ICE vehicle (7.30 liter/100 km).

The breakeven condition between taxed electrolytic hydrogen and taxed gasoline is presented in figure 4.19. The resulting breakeven curve is compared to that of untaxed electrolytic hydrogen presented before in figure 4.18. Notice that the difference in electricity price between the two breakeven curves grows proportionally to the fuel tax rate ($/GJ -HHV).

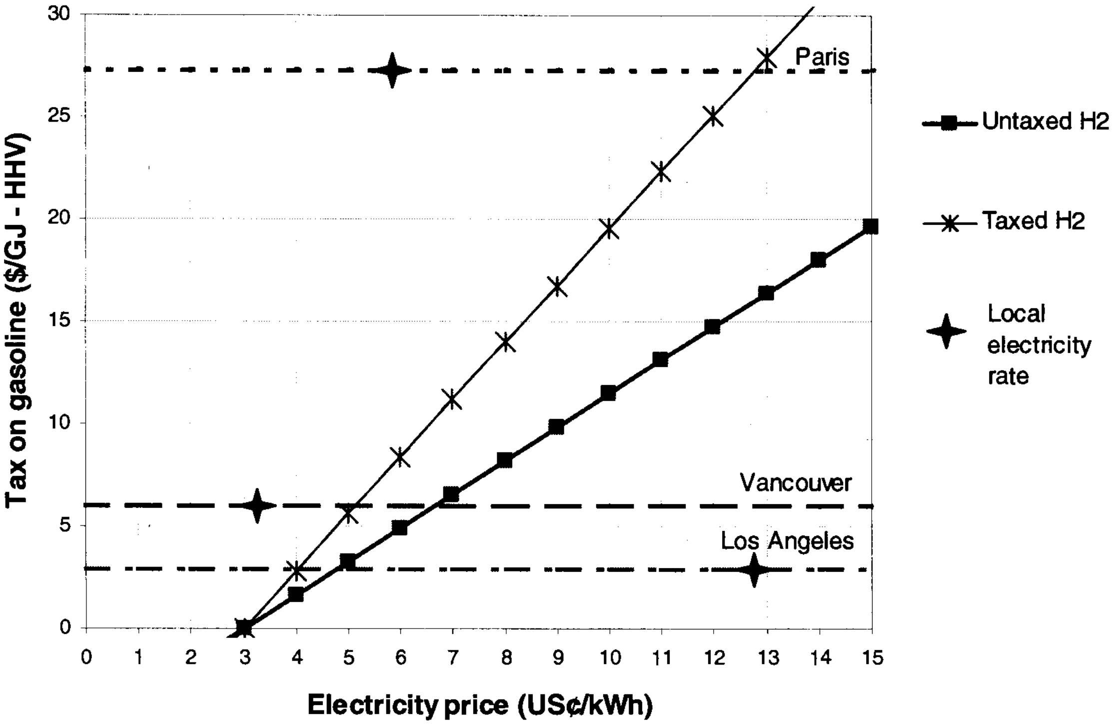


Figure 4.19: Breakeven condition for taxed electrolytic hydrogen to compete with taxed gasoline.

For a given fuel tax rate, the difference between the two breakeven conditions indicates the potential impact of fuel taxes (anywhere between "no fuel tax" to "the same tax rate as gasoline") on the competitive position of electrolytic hydrogen.

Taxing electrolytic hydrogen at the same rate as gasoline shifts the breakeven electricity price down to 4.0 ¢/kWh, 5.1 ¢/kWh and 12.7 ¢/kWh respectively in Los Angeles, Vancouver and Paris. As the fuel tax rate goes up, the difference between the two breakeven curves increases from zero to more than 7 ¢/kWh. So the potential impact of taxing or not electrolytic hydrogen, on an energy content basis, can be more significant (where the local fuel tax rate is high) than the impact of a GHG surtax or credit presented earlier. Recall that a GHG surtax or credit was shown to shift the breakeven electricity price by a maximum of plus or minus 1¢/kWh for a CO_2 valuation of $20/ton of CO_2.

4.4.3.2.3 Fuel Economy Improvements

An additional factor that should be considered, when comparing the projected price of electrolytic hydrogen, is the potential fuel economy improvement of other fuel options. For example, the fuel economy of the gasoline ICE vehicle used for comparison in this section is 7.30 liter/100 km, but with the trend of hybrid vehicles, this number could go down significantly. Assuming that the same car can drive a 50% greater distance on the same amount of fuel, the fuel economy of the gasoline ICE vehicle would then be 4.87 liter/100 km and its fuelling cost would be cut by one third as well.

Figure 4.20 shows the breakeven condition between taxed electrolytic hydrogen and taxed gasoline used in an ICE vehicle with an improved fuel economy (4.87 liter/100 km). The resulting breakeven curve is compared to that of taxed electrolytic hydrogen presented before in figure 4.19. Again, the difference in electricity price between the two breakeven curves increases as the fuel tax rate ($/GJ -HHV) goes up. It merely reflects the fact that a fuel economy improvement results in a larger saving when gasoline is highly taxed.

The impact of a fuel economy improvement in the gasoline ICE vehicle shifts the breakeven electricity price of taxed electrolytic hydrogen down to 1.9 ¢/kWh, 2.4¢/kWh and 5.7 ¢/kWh respectively in Los Angeles, Vancouver and Paris. As the fuel tax rate goes up, the difference between the two breakeven curves increases from 1.6 ¢/kWh to more than 7 ¢/kWh. Thus, fuel economy improvements in the gasoline ICE vehicle have an impact similar in magnitude to that of taxing electrolytic hydrogen.

An important conclusion that can be drawn from looking at figure 4.20 is that the actual electricity prices in Vancouver and Paris are both within 1 ¢/kWh of being competitive with gasoline even in the worst case scenario. That is: electrolytic hydrogen is taxed at the same rate as gasoline, no credits are granted for lower CO_2 emissions, and potential fuel economy improvements of the ICE option are considered. Under these conditions however, the electricity price in Los Angeles would be very far from the breakeven condition (1.9 ¢/kWh vs. 12.8 ¢/kWh).

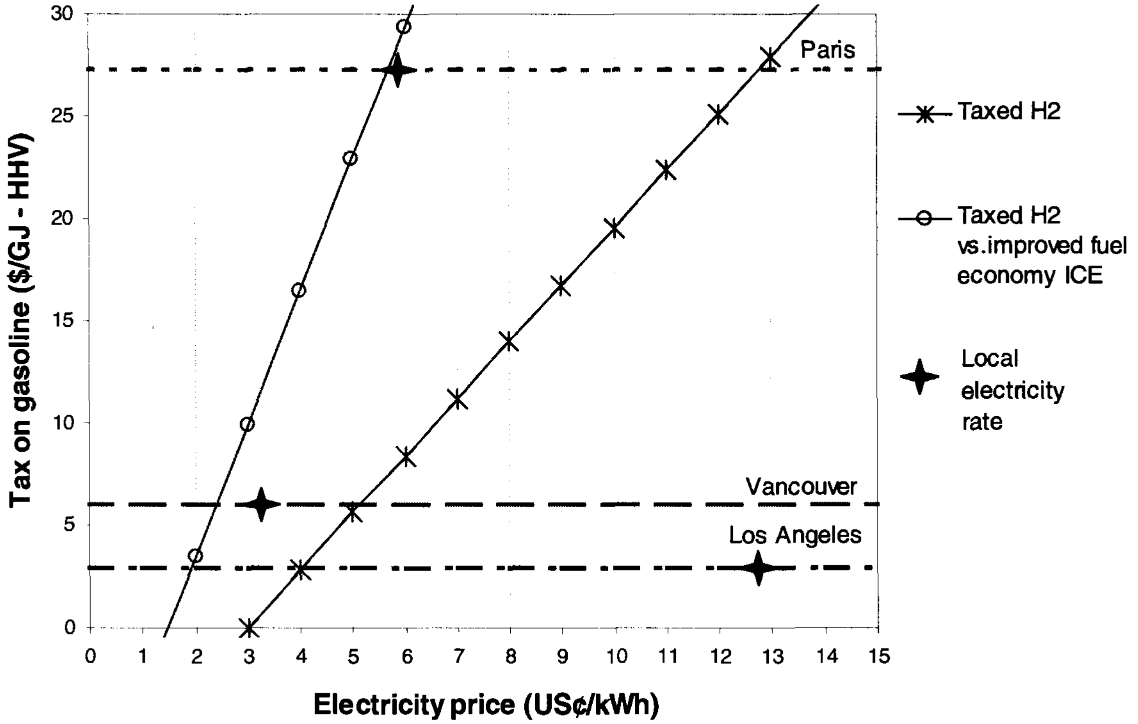


Figure 4.20: Breakeven condition for taxed electrolytic hydrogen to compete with taxed gasoline used in an ICE vehicle with improved fuel economy (50% longer driving range on same amount of fuel).

4.5 Overall Summary of Analysis Results

In an attempt to present the most complete overview of the issues affecting the competitive position of electrolytic hydrogen, the issues "*taxes/credits on fuels*" and "*fuel economy improvements*" are added in the 2-D space presented earlier in the analysis. The result is presented in figure 4.21.

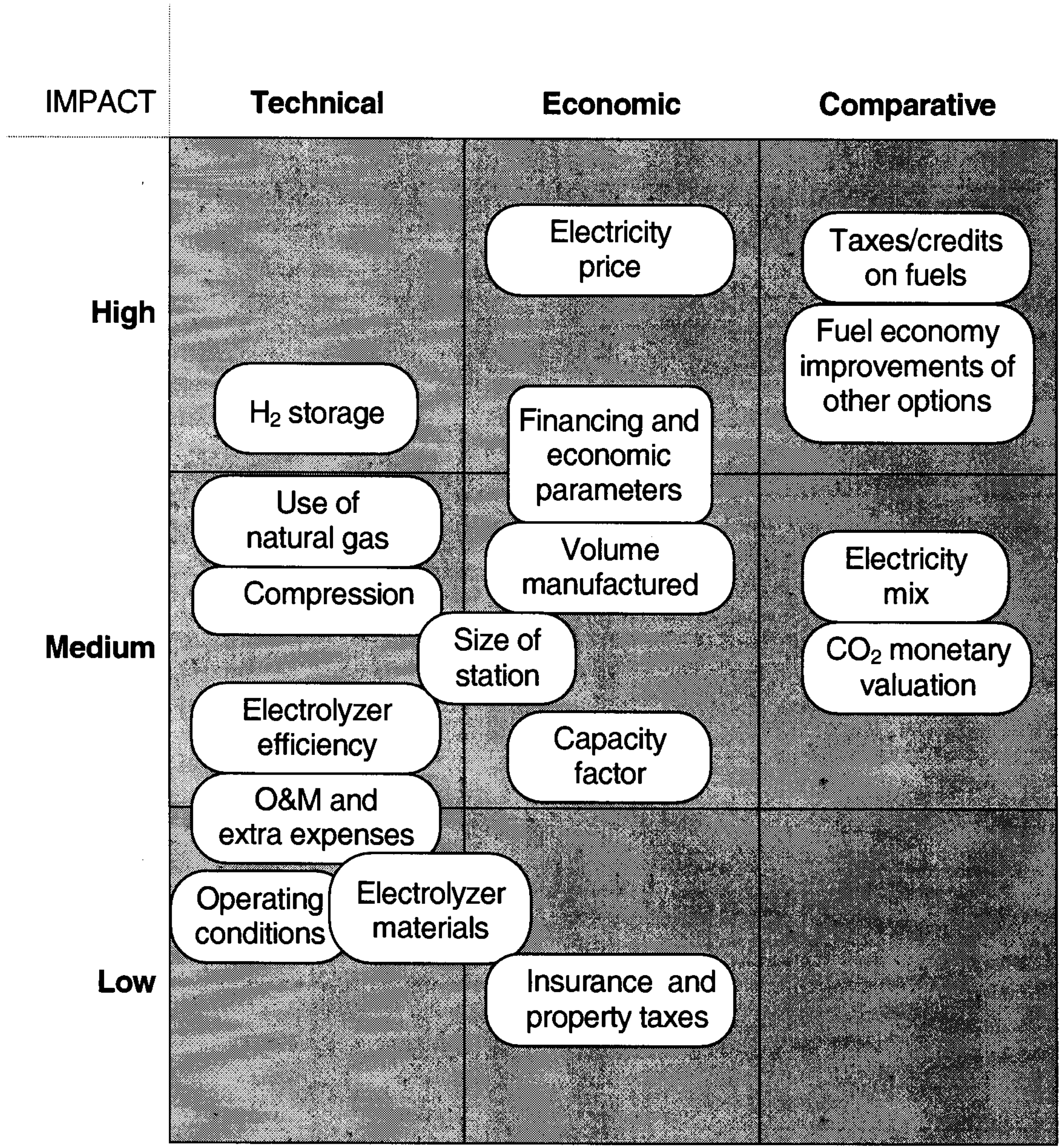


Figure 4.21: Final distribution of issues affecting the price of hydrogen from decentralized electrolysis.

The issues of CO_2 monetary valuation and electricity mix, discussed in the comparative perspective had already been placed in the 2-D space, based on the sensitivity analysis performed earlier. However the impact of other "taxes/credits on fuels" and "fuel economy improvements" had not been discussed yet, since these issues are affected not only by the price of hydrogen, but also by the price of competing fuel options.

Because both of these issues were shown to shift the breakeven condition of the electricity price by as much as 7 ¢/kWh, in locations with a high tax on gasoline (e.g. Paris), they could have an impact comparable to that of the electricity price, which was varied over a range of 6¢/kWh in the sensitivity analysis. Consequently they were both placed in the "high impact" area of the comparative column of figure 4.21. A note of caution about this positioning though: the impact of taxes/credits and fuel economy improvements is directly linked to the local fuel tax rate, so the impact of these issues would be lower in locations with relatively low taxes on gasoline.

Now, in accordance with the proposed approach at the beginning of this chapter, the issues presented in the 2-D space of figure 4.21 can be positioned inside three boxes corresponding to the three increasingly broader perspectives considered in the analysis: technical, economic and comparative. This is done in figure 4.22, which gives an overall visual summary of this thesis' results.

It shows the relative impact of the various issues considered, not only with respect to one another in the same perspective, but also with issues from the other two perspectives. The vertical axis indicates once again the relative impact of each issue on the competitive position of electrolytic hydrogen. One additional feature of this figure is that the boxes of issues primarily determined by site-specific information are coloured in grey. As expected, these issues are found in the economic and comparative perspectives. As a result, a horizontal axis is added below to show the increasing influence of site-specific information as we move from the technical to comparative perspective.

The main analysis results presented in this final figure are summarized in the "Conclusions" chapter.

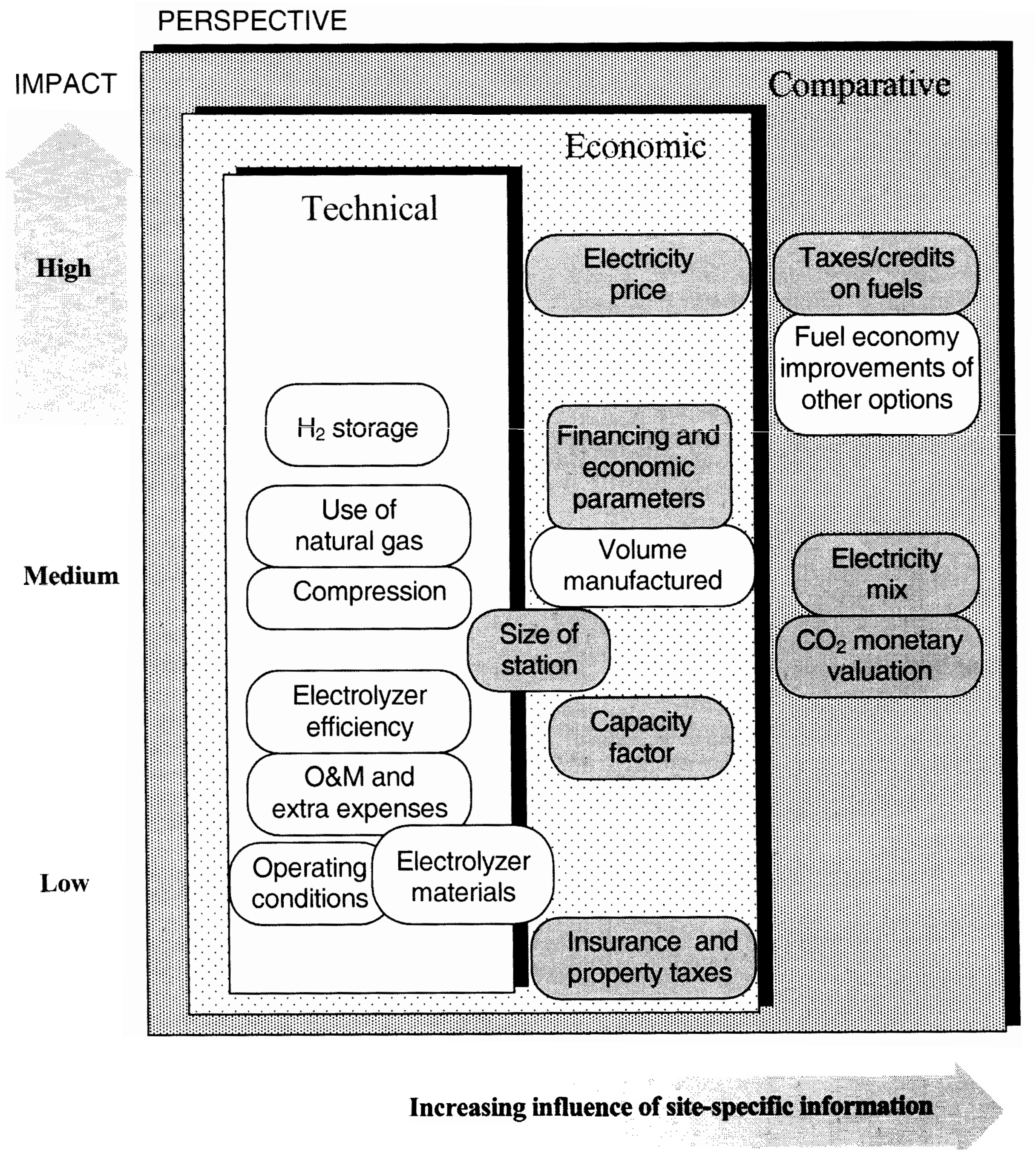


Figure 4.22: Overall summary of the impact of issues affecting the competitive position of electrolytic hydrogen from a technical, economic and comparative perspective.

Chapter 5 – Conclusions and Future Perspectives

5.1 The Approach Revisited

The transition from hydrocarbon-based energy currencies to a "hydrogen economy" will bring about profound transformations in energy systems, probably the most significant ones since the rise of oil at the beginning of the twentieth century. The implications of this transition are far-reaching from a technical, economic, social, political and environmental standpoint. Given that we are still in the early phases of this transition, it is essential that these different perspectives be taken into consideration to maximize informed policy and well planned actions.

One way to facilitate the dialog between people of different background, reflecting these different perspectives, is to design tools that can assist them in understanding each other. The initial motivation for this thesis was to provide one such tool for evaluating electrolytic hydrogen as a fuel option for FCVs. The original cost model developed in the context of this research provides a common ground for discussing the issues that affect the competitive position of electrolytic hydrogen.

The model was used to support an analysis from three different perspectives. As this is first and foremost an engineering thesis, electrolytic hydrogen was first analyzed from the perspective of an engineer, i.e. dominated by technical issues. Then the analysis' framework was broadened to include economic issues, which are most relevant from a business perspective. Finally, it was further broadened to include issues most relevant from the perspective of a policy maker, such as taxes and credits. These three perspectives were respectively labelled "technical", "economic" and "comparative" as shown again in figure 1.6 below.

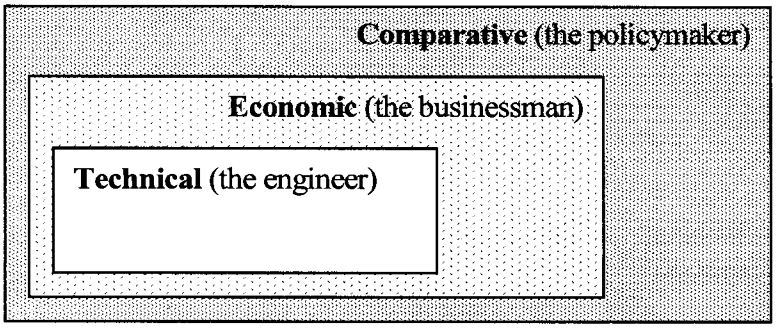


Figure 5.1: Schematic of the three perspectives considered in the analysis

The primary objective of the research was to identify key technical and economic parameters that influence the competitive position of decentralized electrolytic hydrogen as a fuel for FCVs. This was achieved by means of a sensitivity analysis performed on the price of electrolytic hydrogen, using the cost model developed. Based on these sensitivity results, issues that should be prioritized to facilitate the adoption of electrolytic hydrogen were discussed.

A second objective was to quantify the possible economic impact of GHG emissions related to the electricity mix used in the water electrolysis process. This was accomplished once again with the help of the cost model. The magnitude of this impact was evaluated relative to other fuel options, as a function of the electricity mix and the monetary valuation of CO_2.

In the end, this integrated analysis and the cost model in itself constitute additional tools for directing more effectively the actions required to improve the competitive position of electrolytic hydrogen for FCVs.

5.2 Conclusions and Recommendations

A number of conclusions can be drawn from the analysis results presented in Chapter 4. The main ones are presented here, approximately in order of importance in terms of their impact on the competitive position of electrolytic hydrogen. The expression "competitive position" of electrolytic hydrogen is used instead of "price" because it is more general, as it is sometimes the price of the other fuel options to which electrolytic hydrogen is compared that varies. For each of the conclusion points, the perspective(s) to which it relates are mentioned (**T**: technical, **E**: economic, **C**: comparative).

1. *The technical aspect is not the dominant one affecting the competitive position of electrolytic hydrogen.* **(T, E, C)**

   In fact, the analysis showed that some issues in both of the economic and comparative perspectives rank higher in terms of impact on electrolytic hydrogen than the highest issue in the technical perspective (storage). This suggests that the technical aspect has, in general, the lowest impact of the three perspectives considered.

   Efforts should therefore be focused primarily on electricity prices and taxes/credits to maximize the competitive position of electrolytic hydrogen. This is an important result, especially for engineers, who are used to solving problems largely from a technical perspective. It means that even the best technical improvements, although helpful in enhancing the competitiveness of electrolytic hydrogen, are unlikely to produce a decisive advantage.

2. *Strategies for low-cost electricity are key for electrolytic hydrogen to be competitive with other fuel options.* **(E)**

   Access to low-cost electricity remains the number one issue affecting the price of electrolytic hydrogen. Three specific avenues were identified to achieve this goal:

   - Optimizing access to off-peak electricity by establishing new tariff structures better adapted for off-peak electricity.
   - Taking advantage of the interruptible nature of water electrolysis to use spinning reserves of power utilities at low rates, with limited additional GHG emissions.
   - Offering some fiscal incentives for electrolytic hydrogen produced from electricity with low associated GHG emissions. Recall from the analysis portion that the price of electrolytic hydrogen can be thought of in general as proportional to the electricity price plus 1-3 ¢/kWh for capital and O&M costs. Hence a credit in the order of 1-3 ¢/kWh would have an impact comparable to lowering the capital cost of the electrolyzer station to zero.

3. *Site-specific factors have an important impact on electrolytic hydrogen, particularly taxes and credits on fuels.* **(C)**

Analysis of the competitive position of electrolytic hydrogen versus gasoline in three locations (Vancouver, Los Angeles and Paris) showed that hydrogen could be sold at a price comparable to or lower than gasoline (per kilometer) for two of these cities. This assertion is based on actual local electricity rates and gasoline prices, and it holds true even when electrolytic hydrogen is taxed at the same rate as gasoline on an energy content basis.

It is shown that it would be possible today for electrolytic hydrogen to compete with gasoline under favorable conditions of electricity prices and fuel taxes. Taxing fuels on an energy content basis creates an incentive for more efficient fuel options. Fuel economy improvements in ICE vehicles, like those achievable with hybrid cars, would make it harder for electrolytic hydrogen to compete, but not dramatically so.

Other site-specific factors that can influence the price of electrolytic hydrogen, albeit to a lesser extent, include the economic parameters used for the financing of the electrolyzer station and the local electricity mix.

4. *Storage of hydrogen seems to be the dominant technical issue.* **(T)**

This is a surprising result, but the capital cost of hydrogen storage to allow the "fast fill" option turns out to be of the same order or higher than the cost of the electrolyzer and compressor components combined. This is emphasized in very small electrolyzer stations. Approaches suggested in the analysis to remedy this situation include:

- Eliminating the requirements for stationary hydrogen storage by making the "time fill" option acceptable. One particularly ambitious approach is to have a small electrolyzer directly onboard FCVs, to produce hydrogen wherever the FCV can be connected to the electric grid, provided there exists a convenient way to bill this electricity to the user.
- Using a compressor to optimize the fraction of stored hydrogen that can be transferred to the high-pressure tanks of the FCV. This compressor could be the same as the one used for compressing the stored hydrogen in the first place.
- Developing inexpensive hydrogen storage technology.

5. *Power utilities are in the best position to finance & manage electrolyzer stations.* **(E)**

   A utility can generally afford a lower expected rate of return than a business on electrolyzer stations, because its main financial interest comes from additional sales of electricity. Also, utilities themselves usually have access to low-cost financing.

   A utility could offer the flexibility that is necessary to adapt to an evolving market for electrolytic hydrogen. As the demand increases, a utility could replace small electrolyzers by larger ones and move the smaller ones to locations with lower demand. Electrolyzer stations of proper capacity would then be amortized over their full economic life, and their capital cost could be averaged, the most profitable stations compensating for the ones with a lower utilization.

   Using communication technology, utilities could manage distributed electrolyzers as "recallable" loads (i.e. power supplies that can be interrupted when needed), hence promoting access to very low-cost electricity.

6. *The monetary valuation of GHG emissions is generally not sufficient to tilt the balance in favor of electrolytic hydrogen.* **(C)**

   Even at US $20/ton of CO_2, the economic advantage of CO_2-free electrolytic hydrogen with respect to gasoline used in ICE vehicles would be moderate. It would have an impact equivalent to a credit of 1.1 ¢/kWh on electricity. This potential advantage of CO_2-free electrolytic hydrogen vanishes almost completely when compared to hydrogen from decentralized SMR, the maximum impact being equivalent to a credit of 0.4 ¢/kWh on electricity.

   Also, the electricity mix in most locations results in higher GHG emissions than decentralized SMR. For the electricity mix to produce lower GHG emissions than decentralized SMR, at most 35% of the mix can come from natural gas power plants and the rest from CO_2-free electricity. The use of electricity from spinning reserves could be an exception, considering that most of the associated GHG emissions would be produced regardless, for network reliability purposes.

7. *A decentralized hydrogen fuel infrastructure may be better adapted to an emerging market, but there are non-negligible disadvantages to very small stations.* **(T, E)**

   The size of a hydrogen fuelling station has an effect on its requirements to deal with statistical variations in demand. The smaller the station, the greater the statistical variations, and consequently the requirements to deal with them. These requirements are handled primarily by the storage capacity, but also partially by the electrolyzer and compressor, based on a higher peak-to-demand ratio for smaller stations. In addition, larger electrolyzers could often benefit from lower electricity prices.

   This suggests that electrolyzer stations supporting a larger fleet of FCVs (say 50-100 instead of 2-4) could best serve the advantages of a decentralized hydrogen fuelling infrastructure.

8. *Technical issues related to the electrolyzer itself have a limited impact on the competitive position of electrolytic hydrogen.* **(T)**

   The operating conditions of the electrolyzer (temperature, pressure, current density) and its energy efficiency can all have positive effects on the performance and capital cost of the electrolyzer, but their overall effect on the price of electrolytic hydrogen is moderate. The most promising development on that front is probably the potential use of inexpensive heat in high-temperature electrolysis (HTE), which could reduce the electricity requirement by up to 25%.

   The volume of electrolyzer stations manufactured shows a bigger impact on the cost of electrolytic hydrogen than most other technical improvements.

9. *The economic impact of the compression issue is also limited* **(T)**

   Improvements in that area, like the elimination of the compressor by high-pressure electrolysis, would have more impact from an operational standpoint, whereas its impact on the price of hydrogen would be rather modest. If very high-pressure hydrogen storage (700 bar) becomes a standard, the impact of the compression issue could be slightly more important.

10. *The synergy with fuel cell developments and production volumes could have a noticeable impact on the capital cost of electrolyzers. However, synergies with fuel cells could end up favoring decentralized SMR more than water electrolysis.*

    Since the commercialization of stationary fuel cell systems is anticipated to take off prior to any mass market in transportation, and natural gas is the clear dominant fuel option for these stationary systems, small-scale SMR is expected to be well developed in the near future.

    The fuel processor in a stationary fuel cell system (likely based on small-scale SMR) could be slightly oversized to produce excess hydrogen during off-peak periods. This hydrogen could be stored for use in FCVs. Wherever natural gas is available, having a fuel processor that serves a dual role, taking advantage of off-peak periods, could be a more economical option than electrolytic hydrogen.

As a reminder, the reader should bear in mind that all these conclusions about the competitive position of electrolytic hydrogen as a fuel for FCVs are based on a comparison of fuel costs only, independently of the capital and operating costs of the vehicle. In reality, for FCVs to compete with ICE vehicles on an economic basis, it is the life-cycle costs of owning and operating the vehicle that must be similar. Fuel costs typically account for less than 10% of the total cost of owning and operating a car. However, given the high sensitivity of consumers to fuel costs, consumer behavior in itself justifies the comparison of fuel costs separately.

The overall conclusion that emerges from this study is that electrolytic hydrogen could be competitive with gasoline today, with current electrolysis technology, in locations where electricity rates are low and/or fuel taxes are high. At the end of the day, there is no clear-cut answer to whether decentralized electrolytic hydrogen is the best fuelling option for FCV. The only certain answer is that it depends on a variety of issues pertaining to multiple perspectives.

5.3 Future Work

This research covered a wide range of topics associated with decentralized electrolytic hydrogen as a fuel for FCVs, and was consequently limited in depth. More focused research should follow on some of the issues raised here. Various studies have already been done and published since this research was initially started, but much remains to be done. A few directions for future work are suggested:

- Identify the most favorable locations, nationally or internationally for decentralized electrolytic hydrogen stations. These could be locations where electricity price are low compared to natural gas, where the electricity mix has low GHG emissions, where fuel taxes are high, etc. More attention should be paid to comparing specifically hydrogen from decentralized electrolysis with hydrogen from decentralized SMR.

- Investigate the optimal strategies to supply low-cost electricity for the production of electrolytic hydrogen.

- Investigate the technical and economic implications of onboard electrolysis for FCVs.

- Perform a rigorous study of the available tax and credit strategies to maximize the competitive position of electrolytic hydrogen.

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Appendix A – Thermodynamic Voltages for Water Splitting

The cost model of this research calculates the energy requirement of the electrolysis process, based on theoretical considerations from thermodynamics and the energy efficiency of the process, the latter being an input variable in the model.

As explained in chapter 2, the energy requirement of water electrolysis is proportional to the single-cell voltage (for a constant current efficiency). The minimum amount of energy necessary in the form of electricity is proportional to the reversible voltage (E_{rev}). The minimum from electricity and heat combined is proportional to the thermoneutral voltage (E_{tn}). And if the energy necessary to bring the feed water from 25°C to the electrolysis temperature is included, then the total energy requirement is proportional to the so-called higher-heating-value voltage (E_{HHV}). The value of these different voltages as a function of temperature was summarized in a graph of chapter 2, reproduced below (figure A.1). This appendix explains how each of these four theoretical voltage curves were obtained.

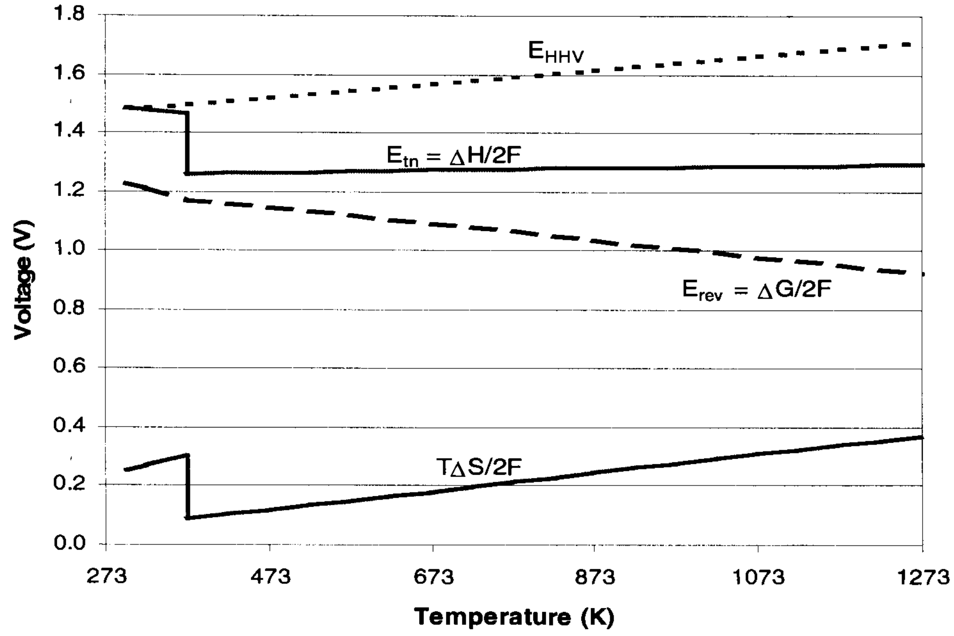

Figure A.1: Theoretical water electrolysis voltages as a function of temperature (at 1 bar).

The reference voltage used in the model to calculate the theoretical minimum energy requirement is the higher-heating-value voltage (E_{HHV}). This is a conservative assumption, as it implies that none of the energy used to heat the feed water to the electrolyzer operating temperature is recycled.

Numerical values for E_{HHV} as a function of temperature were obtained by applying the First Law of Thermodynamics to a simplified version of the electrolysis process. The only reactant entering the electrolyzer is pure liquid water at a temperature $T_o = 298$ K. Work (W) and heat (Q) are then added in the electrolyzer to split water completely into hydrogen and oxygen, the two products coming out at the electrolyzer operating temperature *T*, as shown in figure A.2.

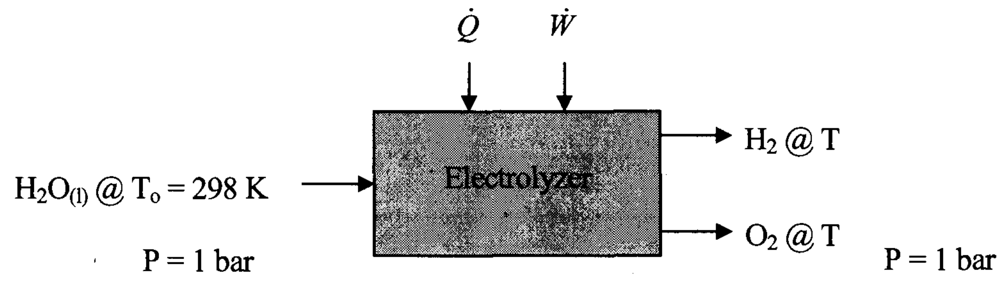

Figure A.2: Schematic of the simplified electrolysis process used to calculate the theoretical energy requirement of the process.

The First Law of Thermodynamics states that energy is conserved. When applied to a control volume, it can be expressed in a general form as:

$$\frac{dE}{dt} = \sum_i \dot{Q}_i + \sum_j \dot{W}_j + \sum_k \dot{m}_k h_k \qquad (\text{A.1})$$

The rate of change of energy in the control volume (*dE/dt*) is equal to the sum of the net heat, work and enthalpy flows into and from the control volume. Here, work done on the control volume by its surrounding is considered positive, as well as the heat input to the control volume.

At steady state, the left hand side of equation (A.1) becomes zero. The magnitude of the combined heat and work input is then equal to the net enthalpy change between the products (exiting the control volume) and reactants (entering the control volume). When the enthalpy flows are expressed in molal terms, equation (A.1) becomes:

$$\dot{Q}+\dot{W}=\sum \dot{n}_p(\bar{h}_f^o+\Delta\bar{h})_p-\sum \dot{n}_r(\bar{h}_f^o+\Delta\bar{h})_r \qquad (\text{A.2})$$

The subscripts "p" and "r" on the right hand side of equation (A.2) stand for products and reactants. The enthalpy of each reactant or product can be expressed as the sum of its enthalpy of formation ($\bar{h}_f^o$) at STP [1] conditions (as indicated by the ^{o} superscript), and the difference in enthalpy between standard temperature (298.15 K) and the temperature T considered ($\Delta\bar{h}$). The molal form of these quantities is indicated by a "bar" over the lower case letter.

If equation (A.2) is divided by the molal flow, it gives:

$$Q+W=\sum N_p(\bar{h}_f^o+\Delta\bar{h})_p-\sum N_r(\bar{h}_f^o+\Delta\bar{h})_r \qquad (\text{A.3})$$

The water-splitting reaction considered here is simply:

$$H_2O \Rightarrow H_2+\tfrac{1}{2}O_2 \qquad (\text{A.4})$$

When equation (A.3) is applied to the water-splitting reaction, the result is:

$$Q+W=(\bar{h}_f^o+\Delta\bar{h})_{H_2}+\frac{1}{2}(\bar{h}_f^o+\Delta\bar{h})_{O_2}-(\bar{h}_f^o+\Delta\bar{h})_{H_2O} \qquad (\text{A.5})$$

Considering that the enthalpy of formation of diatomic gases like molecular oxygen and hydrogen is equal to zero by convention, and that the "$\Delta\bar{h}$" of water is equal to zero because taken at standard temperature 298.15 K, we find:

$$Q+W=\Delta\bar{h}_{H_2}+\frac{1}{2}\Delta\bar{h}_{O_2}-\bar{h}_{f\,H_2O}^o \qquad (\text{A.6})$$

The enthalpy of formation of water at STP is a fixed value: $\bar{h}_{f\,H_2O}^o$= -285.83 kJ/mol. However, the enthalpy of hydrogen and oxygen must be calculated as a function of temperature using some kind of relationship. For an ideal gas, the change in enthalpy between two states can be calculated from the specific heat at constant pressure (C_p) and the temperature of each state, provided there is a relationship to express C_p as a function of temperature. Applying this approach, equation (A.6) becomes:

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[1] Standard temperature and pressure or standard reference state, i.e. 25 °C (298.15 K) and 1 bar.

$$Q+W=\int_{298}^{T} C_{pH_2}(T)dT+\frac{1}{2}\int_{298}^{T} C_{pO_2}(T)dT-\bar{h}^{o}_{f\,H_2O} \qquad (\text{A.7})$$

Standard thermodynamics textbooks generally provide empirical relationships to calculate C_p as a function of temperature for common substances. In the cost model, the following relationships were used to calculate the integrals of equation (A.7) for hydrogen and oxygen [1]:

$$\int_{298}^{T} C_{pH_2}(T)dT=\left[\bar{R}\left(\alpha T+\beta\frac{T^2}{2}+\gamma\frac{T^3}{3}+\delta\frac{T^4}{4}+\varepsilon\frac{T^5}{5}\right)\right]_{298}^{T} \qquad (\text{A.8})$$

with: $\alpha = 3.057$, $\beta = 2.677\times10^{-3}$, $\gamma = 5.810\times10^{-6}$, $\delta = 5.521\times10^{-9}$, $\varepsilon = 1.812\times10^{-12}$, $\bar{R} = 8.314$ kJ/kmol.K

$$\int_{298}^{T} C_{pO_2}(T)dT=\left[\bar{R}\left(\alpha_0 T+\beta_0\frac{T^2}{2}+\gamma_0\frac{T^3}{3}+\delta_0\frac{T^4}{4}+\varepsilon_0\frac{T^5}{5}\right)\right]_{298}^{T} \qquad (\text{A.9})$$

with: $\alpha_o = 3.626$, $\beta_o = 1.878\times10^{-3}$, $\gamma_o = 7.055\times10^{-6}$, $\delta_o = 6.764\times10^{-9}$, $\varepsilon_o = 2.156\times10^{-12}$

Thus, using these relationships it is possible to evaluate the theoretical amount of energy (Q+W) required to split water as a function of temperature, and to heat the feed water from 25°C to the water-splitting temperature *T*. The corresponding higher-heating-value voltage (E_{HHV}) is obtained simply by dividing this minimum energy requirement (Q+W) by nF, where n = 2 for the water-splitting reaction and F is the Faraday constant (96,487). Actual values used in the model to calculate E_{HHV} are presented in table A.1.

The previous paragraphs explain how the values for E_{HHV} (T) were obtained. For the purpose of the cost model, E_{HHV} is the most important voltage since it is the reference voltage used to calculate the minimum energy requirement of the electrolyzer. However, the three other voltage curves appearing in figure (A.1) also provide useful information. Their values were obtained from a computer program that calculates various thermodynamic quantities, based on the molecular properties of the species considered [2].

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[1] Moran M.J., Shapiro H.N. Fundamentals of Engineering Thermodynamics. Third edition, John Wiley and Sons, 1998.

[2] Computer program developed by Dr. David Harrington, University of Victoria, Victoria, BC, Canada, 2000.

T		$h\ H_2$	$h\ O_2$	$h\ H_2O$	W+Q	W+Q	W+Q	$(W+Q)/nF = E_{HHV}$
°C	K	kJ/kmol	kJ/kmol	kJ/kmol	kJ/kmol	kJ/kg H2	kWh/kg H2	V
25	298	0	0	-285830	285830,0	141780,8	39,4	1,481
50	323	722,6	735,9	-285830	286920,5	142321,7	39,5	1,487
100	373	2173,7	2221,5	-285830	289114,5	143410,0	39,8	1,498
150	423	3630,5	3728,0	-285830	291324,5	144506,2	40,1	1,510
200	473	5091,1	5257,5	-285830	293549,9	145610,1	40,4	1,521
250	523	6554,2	6811,3	-285830	295789,9	146721,2	40,8	1,533
300	573	8019,3	8389,6	-285830	298044,1	147839,3	41,1	1,544
350	623	9486,4	9992,1	-285830	300312,4	148964,5	41,4	1,556
400	673	10955,8	11617,9	-285830	302594,8	150096,6	41,7	1,568
450	723	12428,4	13265,7	-285830	304891,2	151235,7	42,0	1,580
500	773	13905,0	14933,7	-285830	307201,8	152381,9	42,3	1,592
550	823	15386,7	16620,1	-285830	309526,7	153535,1	42,6	1,604
600	873	16874,4	18323,1	-285830	311866,0	154695,4	43,0	1,616
650	923	18369,1	20041,0	-285830	314219,6	155862,9	43,3	1,628
700	973	19871,3	21772,2	-285830	316587,4	157037,4	43,6	1,641
750	1023	21381,2	23515,5	-285830	318969,0	158218,7	43,9	1,653
800	1073	22898,6	25270,5	-285830	321363,8	159406,7	44,3	1,665
850	1123	24422,7	27036,9	-285830	323771,2	160600,8	44,6	1,678
900	1173	25952,0	28815,8	-285830	326189,9	161800,5	44,9	1,690
950	1223	27484,0	30608,6	-285830	328618,3	163005,1	45,3	1,703
1000	1273	29015,6	32418,3	-285830	331054,7	164213,7	45,6	1,716

Table A.1: Values used to calculate the higher-heating-value voltage (E_{HHV}) as a function of temperature.

Recall from Chapter 2 that the theoretical energy required for the water-splitting reaction to proceed (ignoring the energy to heat the feed water to the electrolysis temperature), can be expressed through the following thermodynamic equation:

$$\Delta H = \Delta G + T\Delta S \tag{A.10}$$

where ΔH is the enthalpy change of the reaction, ΔG is the Gibbs free energy change, T is the electrolysis temperature (in Kelvin) and ΔS is the entropy change.

The Gibbs free energy change ΔG corresponds to the portion of the total reaction energy that must be supplied in the form of electricity, when water splitting is performed by electrolysis. The term "TΔS" corresponds to the portion of the total reaction energy that could thermodynamically be covered by thermal energy.

All the terms of equation (A.10) can be divided by "$2F$" (F is the Faraday constant) to give respectively the thermoneutral voltage (E_{tn}), the reversible voltage (E_{rev}) and the voltage that corresponds to the portion of energy which could theoretically be covered by heat ($T\Delta S/2F$).

$$\frac{\Delta H}{2F} = \frac{\Delta G}{2F} + \frac{T\Delta S}{2F} \tag{A.11}$$

$$E_{tn} = \frac{\Delta H}{2F} \tag{A.12}$$

$$E_{rev} = \frac{\Delta G}{2F} \tag{A.13}$$

Thus, calculating the values of ΔH and ΔG as a function of temperature, at standard pressure of 1 bar, is sufficient to obtain the value of the three voltages mentioned above. These two quantities were calculated respectively by taking the negative of the enthalpy of formation and the negative of the Gibbs function of formation of water at temperature T. Hence the two corresponding equations used to calculate the enthalpy change and Gibbs free energy change for the water-splitting reaction are:

$$\Delta H(T) = -\Delta_f H^0_{H2O}(T) = -\{\Delta_f H^0_{H2O}(0K) + [H_{H2O}(T) - H_{H2O}(0K)] - [H_{H2}(T) - H_{H2}(0K)] - 0.5[H_{O2}(T) - H_{O2}(0K)]\} \tag{A.14}$$

$$\Delta G(T) = -\Delta_f G^0_{H2O}(T) = -\{\Delta_f G^0_{H2O}(0K) + [G_{H2O}(T) - G_{H2O}(0K)] - [G_{H2}(T) - G_{H2}(0K)] - 0.5[G_{O2}(T) - G_{O2}(0K)]\} \tag{A.15}$$

All the input values for these two equations were obtained from the computer program referred to earlier [1], and from tables of chemical thermodynamic properties [2].

The resulting values for $\Delta H(T)$ and $\Delta G(T)$ are then divided by 2F to give the corresponding thermoneutral (E_{tn}) and reversible (E_{rev}) voltages. The voltage that corresponds to the portion of energy which could theoretically be covered by heat ($T\Delta S/2F$) is simply obtained from the difference between E_{tn} and E_{rev}, in accordance with equation (A.11). All the voltage values used to generate figure (A.1) are summarized in table (A.2).

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[1] Computer program developed by Dr. David Harrington, University of Victoria, Victoria, BC, Canada, 2000.

[2] National Bureau of Standards. The NSB Tables of Chemical Thermodynamic Properties. Journal of Physics and Chemical Reference Data, Vol. 11, 1982, Supplement No. 2.

	T [°C]	T [K]	$E_{\tau\nu} = \Delta H/2F$ (1)	$E_{\rho\varepsilon\varpi} = \Delta G/2F$ (1)	$T\Delta S/2F$ (2)	E_{HHV} (3)
H_2O liq.	25	298	1,481	1,229	0,252	1,481
	50	323	1,477	1,208	0,269	1,487
	100	373	1,469	1,167	0,302	1,498
H_2O gas	100	373	1,258	1,168	0,090	1,498
	150	423	1,261	1,156	0,105	1,509
	200	473	1,263	1,144	0,120	1,521
	250	523	1,266	1,131	0,135	1,533
	300	573	1,268	1,118	0,150	1,544
	350	623	1,270	1,105	0,166	1,556
	400	673	1,273	1,091	0,181	1,568
	450	723	1,275	1,078	0,197	1,580
	500	773	1,277	1,064	0,213	1,592
	550	823	1,279	1,050	0,229	1,604
	600	873	1,280	1,036	0,244	1,616
	650	923	1,282	1,022	0,260	1,628
	700	973	1,284	1,008	0,276	1,640
	750	1023	1,285	0,994	0,292	1,653
	800	1073	1,287	0,980	0,307	1,665
	850	1123	1,288	0,965	0,323	1,678
	900	1173	1,290	0,951	0,339	1,690
	950	1223	1,291	0,936	0,354	1,703
	1000	1273	1,292	0,922	0,370	1,716

Table A.2: Summary table of the relevant voltages used for the water-splitting reaction

Most standard thermodynamics textbooks provide the necessary information to reproduce these results. Some references also provide a more extensive treatment of the First and Second Laws of Thermodynamics applied to water electrolysis [4,5].

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[1] Calculated from the values obtained with the computer program developed by Dr. David Harrington.

[2] Simply the difference between E_{tn} and E_{rev}.

[3] Calculated from application of First-Law of Thermodynamics, using empirical relationships for C_{pH2} and C_{pO2}.

[4] Noyes Data Corporation. Hydrogen Manufacture by Electrolysis, Thermal Decomposition and Unusual Techniques. Edited by M.S. Casper, Park Ridge, NJ, U.S.A., 1978

[5] Winter C.J. Hydrogen as an Energy Carrier - Technologies, Systems, Economy. Joachim Nitsch (Eds.), Springer-Verlag, 1988.

Appendix B – Fuel Economy Conversions

To facilitate comparisons between the different fuel options considered in this research, their respective fuel economies have all been expressed in terms of equivalent gasoline fuel economy. This is a common practice in most studies comparing fuel options for FCVs.

When gasoline is the fuel considered, either in an ICE vehicle or a FCV, the average fuel consumption can be expressed directly in liters of gasoline per 100 kilometres (lilter/100 km) or in miles per gallon (mpg) in the United States. When the fuel considered is methanol or hydrogen however, their energy content has to be translated in a gasoline equivalent. This can be done by comparing fuels on a higher-heating-value (HHV) basis or on a lower-heating-value basis (HHV). Some studies use the higher heating value (HHV), some use the lower heating value (LHV), and others do not specify which one is used.

The use of the LHV-basis can be justified by the fact that no vehicles in use or currently being developed have power plants capable of condensing the moisture of combustion [1]. On the other hand, the main argument for comparison on a HHV-basis is that it reflects more accurately the true energy content of a fuel. In this research, fuel comparisons are all made on a HHV-basis. The impact of using HHV instead of LHV is quantified for hydrogen and methanol, as shown below.

A table from the Alternative Fuels Data Centre [1] is the reference used for the energy content of gasoline and methanol, whereas a different source is used for the energy content of hydrogen[2].

Energy content of gasoline:

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[1] Alternative Fuels Data Centre web site: www.afdc.doe.gov/pdfs/fueltable.pdf, "Properties of Fuels" table.

[2] Norbeck J.M. et al. Hydrogen Fuel for Surface Transportation. Published by Society of Automotive Engineers, Inc., Warrendale, PA, U.S.A., 1996.

131,670 kJ/gallon (HHV) / 3.7854 gallon/litre = 34,784 kJ/liter of gasoline (HHV)
121,330 kJ/gallon (LHV) / 3.7854 gallon/litre = 32,052 kJ/liter of gasoline (LHV)

Energy content of methanol:

68,156 kJ/gallon (HHV) / 3.7854 gallon/litre = 18,005 kJ/liter of methanol (HHV)
59,947 kJ/gallon (LHV) / 3.7854 gallon/litre = 15,836 kJ/liter of methanol (LHV)

Energy content of hydrogen:

141,860 kJ/kg of hydrogen (HHV)
119,930 kJ/kg of hydrogen (LHV)

Example of fuel economy conversions with the base case values used in the cost model:

The base case fuel economy of the gasoline ICE vehicle is 7.30 liter/100 km. In terms of the energy requirement to drive 100 kilometers, it means:

7.30 liter/100 km * 34,784 kJ/liter of gasoline (HHV) = 253,923 kJ/ 100 km (HHV)

7.30 liter/100 km * 32,052 kJ/liter of gasoline (LHV) = 233,980 kJ/ 100 km (LHV)

The base case fuel economy of the methanol FCV is 4.19 liter/100 km, in gasoline equivalent. This value is the same as the one used in the Pembina Institute's report [1]. Assuming this value is taken as the gasoline equivalent of methanol (MeOH) on a HHV-basis, it means that the energy requirement to drive 100 kilometers is:

4.19 liter /100 km * 34,784 kJ/liter of gasoline (HHV) = 145,745 kJ/ 100 km (HHV)

or in terms of actual methanol consumption:

[145,745 kJ/ 100 km] / [18,005 kJ/liter MeOH (HHV)] = 8.09 litre MeOH/ 100 km

If the same fuel economy value of 4.19 liter/100 km is taken as the gasoline equivalent of methanol, but on a LHV-basis instead, the energy requirement to drive 100 kilometers is then:

4.19 liter /100 km * 32,052 kJ/liter of gasoline (LHV) = 134,298 kJ/ 100 km (LHV)

or in terms of actual methanol consumption:

[134,298 kJ/ 100 km] / [15,836 kJ/liter MeOH (LHV)] = 8.48 litre MeOH/ 100 km

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[1] Pembina Institute for Appropriate Development, Climate-Friendly Hydrogen Fuel: A Comparison of the Life-cycle Greenhouse Gas Emissions for Selected Fuel Cell Vehicle Hydrogen Production Systems. Report written with support from The David Suzuki Foundation, March 2000, 44 p.

So the same fuel economy value of 4.19 liter/100 km (in gasoline equivalent) translates in a slightly higher methanol consumption (about 4.8%) when gasoline and methanol are compared on a LHV-basis instead of HHV-basis. Thus, by assuming that the fuel economy value for methanol is given on a HHV instead of LHV-basis in the reference source [1], the model may be underestimating methanol consumption by about 5%.

The base case fuel economy of the hydrogen FCV is 3.02 liter/100 km, in gasoline equivalent. Assuming this value is taken as the gasoline equivalent of hydrogen (H_2) on a HHV-basis, it means that the energy requirement to drive 100 kilometers is:

3.02 liter/100 km * 34,784 kJ/liter of gasoline (HHV) = 105,048 kJ/ 100 km (HHV)
or in terms of actual hydrogen consumption:
[105,048 kJ/100km] / [141,860 kJ/kg H_2 (HHV)] = 0.741 kg H_2/100km $\boxed{135 \text{ km/kg } H_2}$

If the same fuel economy value of 3.02 liter/100 km is taken as the gasoline equivalent of hydrogen, but on a LHV-basis instead, the energy requirement to drive 100 kilometers is then:

3.02 liter/100 km * 32,052 kJ/liter of gasoline (LHV) = 96,797 kJ/ 100 km (LHV)
or in terms of actual hydrogen consumption:
[96,797 kJ/100km] / [119,930 kJ/kg H_2 (LHV)] = 0.807 kg H_2/100km $\boxed{124 \text{ km/kg } H_2}$

Hence, the same fuel economy value of 3.02 liter/100 km translates in a higher hydrogen consumption (about 9%) when gasoline and hydrogen are compared on a LHV-basis instead of HHV-basis. However, the base case value of 3.02 liter/100 km (HHV) used in the model is approximately 8% higher than the value used in the reference source (2.79 liter/100 km) [1]. The net result is that the base case hydrogen consumption (135 km/kg H_2) is nearly the same as the one used in the reference source (134 km/kg H_2), assuming they used the LHV-basis to express the "gasoline-equivalent" fuel economy of the hydrogen FCV.

To summarize, assuming that fuel comparisons are made on a HHV-basis rather than LHV-basis may favor methanol by about 5% and hydrogen by 9%, when gasoline is the reference fuel.

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[1] Pembina Institute for Appropriate Development, Climate-Friendly Hydrogen Fuel: A Comparison of the Life-cycle Greenhouse Gas Emissions for Selected Fuel Cell Vehicle Hydrogen Production Systems. Report written with support from The David Suzuki Foundation, March 2000, 44 p.

Appendix C – Cost Model Developed in Microsoft Excel

The following is a print out of the actual cost model developed in Excel 2000. It consists of six worksheets, of which the most relevant sections are printed here.

They include, in the order presented:

- 7 pages from the *Input Summary* worksheet
- 4 pages from the *Total Cost* worksheet
- 3 pages from the *Capital + O&M Cost* worksheet
- 2 pages from the *Energy Cost* worksheet
- 2 pages from the *GHG Cost or Saving* worksheet
- 3 pages from the *Site-Specific Information* worksheet

The cost model includes a total of 103 interactive input cells. More than half are of these input cells are related to other fuel options beside electrolytic hydrogen, and site-specific information.

Explanation of Cells Background Color

To facilitate the understanding of the various values displayed in this model, a code of colors has been used.

▨	Yellow cells identify interactive input cells.
▨	Green cells are non-interactive cells that simply summarize (in the "Input Summary" worksheet) the values entered in all the yellow cells of the model.
▩	Blue cells identify the main output cells of the model.
▨	Orange cells identify non-interactive input cells to the model, in the sense that their information content can be used as reference for interactive input, but they are not directly linked to any other cells.

Summary of Input Variables

1) Need for Hydrogen Fuel

Variable		Units	Value
V	Number of vehicles served by station	-	100
M	Average annual mileage per vehicle	km/yr	19200
f_e	Average fuel economy	km/kg H2	135

2) Variables Influencing Capital + O&M Cost

R_{pd}	Ratio of peak H2 production to average demand	-	1.1
f	Capacity factor (average use [hours per day] / 24h)	-	0.75
e_u	Unit cost of electrolyzer per kW_e	$\$/kW_e$	245.00
c_u	Unit cost of compressor per kW_{out} of H2 (HHV)	$\$/kW_{out}$ (HHV)	200
D	Equivalent number of days of storage	days	0.432
A	Available fraction of stored hydrogen	-	0.4
s_u	Storage capital cost per kg of stored H2 (HHV)	$\$/kg\ H_2$	357.4
x	Capital cost of balance of plant	$	7690

Variables Involved in Financing the Electrolysis Station

If treated as a home appliance, enter 1

If treated as a business investment, enter 2			2	
N	Economic recovery period	years	10	
i_m	Mortgage interest rate (if financed as an appliance)	%	9.0	for home appliance case
T_p	Personal tax rate of home owner	%	35.0	for home appliance case
i	General inflation rate	%	2.7	for business case
r	After-tax real rate of return on investment (in constant dollars)	%	10.0	for business case
T_b	Business tax rate	%	26.0	for business case

O&M Cost

op	Annual operating and maintenance costs	% of Ccap	**3.77**
ins	Annual insurance	% of Ccap	**0**
t_p	Annual property taxes	% of Ccap	**0**

as a percentage of the total installed capital cost of the electrolytic hydrogen refuelling station

Extraordinary expenses

E_1	extraordinary expense 1	$	**0**
n_1	year in which extraordinary expense 1 occurs	-	**0**
E_2	extraordinary expense 2	$	**0**
n_2	year in which extraordinary expense 2 occurs	-	**0**
E_3	extraordinary expense 3	$	**0**
n_3	year in which extraordinary expense 3 occurs	-	**0**
E_4	extraordinary expense 4	$	**0**
n_4	year in which extraordinary expense 4 occurs	-	**0**
E_5	extraordinary expense 5	$	**0**
n_5	year in which extraordinary expense 5 occurs	-	**0**

3) Variables Influencing Energy Cost

η_e	Energy efficiency of electrolyzer	%	**80**
	$\frac{\text{\{Total theoretical energy required by electrolyzer\}}}{\text{\{Energy input e- + NG (HHV)\}}}$		
η_c	Compressor efficiency (with respect to adiabatic compression)	%	**75**
P_{e^-}	Electricity price	$/kWh	**0.030**
P_{NG}	Natural gas price	$/GJ	**3.00**
α	Fraction of energy required for electrolysis provided by NG	-	**0**
T	Electrolysis temperature	°C	**70**
P_i	Electrolysis pressure (also inlet pressure to compressor)	bar	**1**
P_o	Outlet pressure from compressor (also hydrogen storage pressure)	bar	**413.7**

4) Variables Influencing the Greenhouse Gas "Added Cost/Saving" Component

Treatment of C_{GHG} (added cost(+) or saving (-) due to GHG evaluation)

	0
To exclude the impact of C_{GHG}, on the unit cost of H2 (U)	enter 0
To include C_{GHG} considering the alternative option:	
Gasoline ICE,	enter 1
Gasoline FCV with on-board reforming,	enter 2
Methanol FCV with on-board reforming,	enter 3
Hydrogen FCV from decentralized SMR,	enter 4

Monetary Evaluation of Greenhouse Gas Emissions

E_{CO2}	Evaluation of CO2 equivalent emissions	US$/ton CO_2	20

Fuel Economy of Other Fuel Options

Option	liter of gasoline equiv. (HHV) per 100 km
Gasoline ICE	7.30
Gasoline FCV *on-board reforming*	6.11
Methanol FCV *on-board reforming*	4.19
Hydrogen FCV from decentralized SMR	3.02

Base Case for Each Other Fuel Option

Option	GHG emissions g ($CO_{2\,equiv.}$)/km driven	liter of gasoline equiv. (HHV) per 100 km
Gasoline ICE	248	7.30
Gasoline FCV on-board reforming	193	6.11
Methanol FCV on-board reforming	162	4.19
Hydrogen FCV from decentralized SMR	80	2.79

Location **Vancouver** 1

For Vancouver, Canada, enter **1**
For Los Angeles,USA, enter **2**
For Paris, France, enter **3**
For another location enter **4**
(Other location, specified in worksheet "Site-Specific Info")

5) Site-Specific Information

Affecting Comparison with Other Fuelling Options

Item	Units	Location			
		Vancouver Canada	Los Angeles United States	Paris France	**Other Location Country**
Gasoline retail price	$/liter	**0.44**	**0.37**	**1.21**	**0.96**
Tax on gasoline	$/liter	**0.21**	**0.10**	**0.95**	**0.54**
Untaxed Methanol retail price	$/liter	**0.20**	**0.20**	**0.20**	**0.20**
Hydrogen from decentralized SMR	$/kg H2	**2.00**	**2.00**	**2.00**	**2.00**

Affecting Greenhouse Gas Added Cost or Saving

Electricity Mix Vancouver

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_{2\ equiv.}$)/kWh delivere	g (CO$_{2\ equiv.}$)/kWh delivered
	0	Coal	1071	0
	1	Oil	855	9
	5	Natural Gas	605	30
	0	Nuclear	16	0
	91	Hydro	4	4
	0	Wind	36	0
	0	Solar	193	0
	3	Other	0	0
Total	100			42

Electricity Mix Los Angeles

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_{2\ equiv.}$)/kWh delivere	g (CO$_{2\ equiv.}$)/kWh delivered
	11	Coal	1071	118
	0	Oil	855	0
	50	Natural Gas	605	303
	16	Nuclear	16	3
	10	Hydro	4	0
	1.5	Wind	36	1
	0.5	Solar	193	1
	11	Other	0	0
Total	100			425

Electricity Mix Paris

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_{2\ \mathrm{equiv.}}$)/kWh delivere	g (CO$_{2\ \mathrm{equiv.}}$)/kWh delivered
	3	Coal	1071	32
	0	Oil	855	0
	1	Natural Gas	605	6
	82	Nuclear	16	13
	14	Hydro	4	1
	0	Wind	36	0
	0	Solar	193	0
	0	Other	0	0
Total	100			52

Electricity Mix: (Other location)

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_{2\ \mathrm{equiv.}}$)/kWh delivere	g (CO$_{2\ \mathrm{equiv.}}$)/kWh delivered
	70	Coal	1071	750
	0	Oil	855	0
	20	Natural Gas	605	121
	0	Nuclear	16	0
	10	Hydro	4	0
	0	Wind	36	0
	0	Solar	193	0
	0	Other	0	0
Total	100			871

Total Cost of Electrolytic Hydrogen

	Variable		Units	Value
1)	U	Unit cost of H2	\$/kg	2.96
2)	C	Total annual cost of H2	\$/yr	42100
3)	Y	Annual H2 production from station	kg/yr	14222.2
	C_c	Annual capital and O&M cost	\$/yr	17699
	C_e	Annual energy cost	\$/yr	24401
	C_{GHG}	Annual added cost(+) or saving (-) due to GHG evaluation	\$/yr	0

Compared to: No comparison

1) $U = \frac{C}{Y}$

2) $C = C_c + C_e(+C_{GHG})$ **

Because C_{GHG} is a relative term depending on the alternative option considered, it is possible to include or exclude C_{GHG} in the total annual cost of H2

Treatment of C_{GHG}

	0
To exclude the impact of C_{GHG}, on the unit cost of H2 (U)	enter 0
To include C_{GHG} considering the alternative option:	
Gasoline ICE,	enter 1
Gasoline FCV with on-board reforming,	enter 2
Methanol FCV with on-board reforming,	enter 3
Hydrogen FCV from decentralized SMR,	enter 4

3) $Y = V\frac{M}{f_e}$

	V	Number of vehicles served by station	-	**100**
4)	**M**	Average annual mileage per vehicle	km/yr	**19200**
5)	**f_e**	Average fuel economy	km/kg H2	**135**

4) If necessary, the required annual hydrogen production (Y) could be calculated using the specific mileage (M_i) and fuel economy ($(f_e)_i$) of the various vehicles to be served by the station:

$$Y = V\frac{M}{f_e} = \sum_{i=1}^{V}\frac{M_i}{(f_e)_i}$$

5) The fuel economy of a vehicle (f_e), in km driven per kg of H2, can be calculated:

A) Directly from the average energy input required (HHV) per km driven

f_e [km/kg H2] = ***energy required (HHV)*** *[kJ/km]* / ***141,860*** *[kJ/kg H2]*

B) From the equivalent fuel economy if gasoline (HHV) were used,
either in equivalent liters of gasoline per 100 km driven

f_e [km/kg H2] = **407.83 / Lphkm** (using HHV values for both gasoline and H2)

or in miles per US gallon of gasoline equivalent (mpgge)

f_e [km/kg H2] = **1.7339 * mpgge** (using HHV values for both gasoline and H2)

Lphkm: fuel economy in liters of gasoline equivalent (HHV) per 100 km
mpgge: fuel economy in miles per US gallon of gasoline equivalent (HHV)

For consistence in this research, the higher-heating-value is always the one used for gasoline methanol and hydrogen when using equivalent fuel economy.

Electricity Mix Paris

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_2$ $_{equiv.}$)/kWh delivere	g (CO$_2$ $_{equiv.}$)/kWh delivered
	3	Coal	1071	32
	0	Oil	855	0
	1	Natural Gas	605	6
	82	Nuclear	16	13
	14	Hydro	4	1
	0	Wind	36	0
	0	Solar	193	0
	0	Other	0	0
Total	100			52

Electricity Mix: (Other location)

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_2$ $_{equiv.}$)/kWh delivere	g (CO$_2$ $_{equiv.}$)/kWh delivered
	70	Coal	1071	750
	0	Oil	855	0
	20	Natural Gas	605	121
	0	Nuclear	16	0
	10	Hydro	4	0
	0	Wind	36	0
	0	Solar	193	0
	0	Other	0	0
Total	100			871

Total Cost of Electrolytic Hydrogen

	Variable		Units	Value
1)	U	Unit cost of H2	\$/kg	2.96
2)	C	Total annual cost of H2	\$/yr	42100
3)	Y	Annual H2 production from station	kg/yr	14222.2
	C_c	Annual capital and O&M cost	\$/yr	17699
	C_e	Annual energy cost	\$/yr	24401
	C_{GHG}	Annual added cost(+) or saving (-) due to GHG evaluation	\$/yr	0

Compared to: No comparison

1) $U = \frac{C}{Y}$

2) $C = C_c + C_e (+C_{GHG})$ **

Because C_{GHG} is a relative term depending on the alternative option considered, it is possible to include or exclude C_{GHG} in the total annual cost of H2

Treatment of C_{GHG}

	0
To exclude the impact of C_{GHG}, on the unit cost of H2 (U)	enter **0**
To include C_{GHG} considering the alternative option:	
Gasoline ICE,	enter **1**
Gasoline FCV with on-board reforming,	enter **2**
Methanol FCV with on-board reforming,	enter **3**
Hydrogen FCV from decentralized SMR,	enter **4**

3) $Y = V \frac{M}{f_e}$

	V	Number of vehicles served by station	-	**100**
4)	**M**	Average annual mileage per vehicle	km/yr	**19200**
5)	**f_e**	Average fuel economy	km/kg H2	**135**

4) If necessary, the required annual hydrogen production (Y) could be calculated using the specific mileage (M_i) and fuel economy ($(f_e)_i$) of the various vehicles to be served by the station:

$$Y = V\frac{M}{f_e} = \sum_{i=1}^{V}\frac{M_i}{(f_e)_i}$$

5) The fuel economy of a vehicle (f_e), in km driven per kg of H2, can be calculated:

A) Directly from the average energy input required (HHV) per km driven

f_e [km/kg H2] = ***energy required (HHV)*** *[kJ/km] /* ***141,860*** *[kJ/kg H2]*

B) From the equivalent fuel economy if gasoline (HHV) were used,
either in equivalent liters of gasoline per 100 km driven

f_e [km/kg H2] = **407.83 / Lphkm** (using HHV values for both gasoline and H2)

or in miles per US gallon of gasoline equivalent (mpgge)

f_e [km/kg H2] = **1.7339 * mpgge** (using HHV values for both gasoline and H2)

Lphkm: fuel economy in liters of gasoline equivalent (HHV) per 100 km
mpgge: fuel economy in miles per US gallon of gasoline equivalent (HHV)

For consistence in this research, the higher-heating-value is always the one used for gasoline methanol and hydrogen when using equivalent fuel economy.

Total Cost of Electrolytic Hydrogen

	$/kg H2	$/lb H2	$/GJ HHV	%
Cost of energy	1.72	0.78	12.09	58
Cost of O&M	0.19	0.08	1.32	6
Cost of storage	0.23	0.10	1.59	8
Cost of electrolyzer	0.43	0.20	3.06	15
Cost of compressor	0.28	0.13	1.99	10
Cost of bop	0.12	0.05	0.81	4
Cost of extraordinary expenses	0.00	0.00	0.00	0
Total	2.96	1.34	20.87	100

Relative cost/saving due to GHG emissions evaluation

Assuming a GHG evaluation of:	20 US$/tonne CO_2 equivalent

Compared to:

Added cost (positive) or saving (negative)

Gasoline ICE		$/kg H2	$/lb H2	$/GJ HHV	%
With an equivalent fuel economy of (liter/100km) HHV*:	7.30	-0.62	-0.28	-4.38	-21
Total		2.34	1.06	16.49	79

Gasoline FCV with on-board reforming

With an equivalent fuel economy of (liter/100km) HHV*:	6.11	-0.47	-0.21	-3.33	-16
Total		2.49	1.13	17.54	84

Methanol FCV with on-board reforming

With an equivalent fuel economy of (liter/100km) HHV*:	4.19	-0.39	-0.18	-2.74	-13
Total		2.57	1.17	18.13	87

Hydrogen FCV from decentralized SMR

With an equivalent fuel economy of (liter/100km) HHV*:	3.02	-0.18	-0.08	-1.30	-6
Total		2.78	1.26	19.56	94

Total Cost of Electrolytic Hydrogen

	$/kg H2	$/lb H2	$/GJ HHV	%
Cost of energy	1.72	0.78	12.09	58
Cost of O&M	0.19	0.08	1.32	6
Cost of storage	0.23	0.10	1.59	8
Cost of electrolyzer	0.43	0.20	3.06	15
Cost of compressor	0.28	0.13	1.99	10
Cost of bop	0.12	0.05	0.81	4
Cost of extraordinary expenses	0.00	0.00	0.00	0
Total	2.96	1.34	20.87	100

Relative cost/saving due to GHG emissions evaluation

Assuming a GHG evaluation of:	20	US$/tonne CO_2 equivalent

Compared to:

Added cost (positive) or saving (negative)

Gasoline ICE

		$/kg H2	$/lb H2	$/GJ HHV	%
With an equivalent fuel economy of (liter/100km) HHV*:	7.30	-0.62	-0.28	-4.38	-21
Total		2.34	1.06	16.49	79

Gasoline FCV with on-board reforming

With an equivalent fuel economy of (liter/100km) HHV*:	6.11	-0.47	-0.21	-3.33	-16
Total		2.49	1.13	17.54	84

Methanol FCV with on-board reforming

With an equivalent fuel economy of (liter/100km) HHV*:	4.19	-0.39	-0.18	-2.74	-13
Total		2.57	1.17	18.13	87

Hydrogen FCV from decentralized SMR

With an equivalent fuel economy of (liter/100km) HHV*:	3.02	-0.18	-0.08	-1.30	-6
Total		2.78	1.26	19.56	94

Cost Comparison with Other Fuelling Options

		Fuel cost to consumer	Including effect of GHG emission evaluation		Tax on fuel Vancouver $/GJ-HHV
			Added cost	Total	
		¢/km driven	¢/km driven		
Gasoline ICE		3.18	0.50	3.67	5.98
Untaxed Gasoline ICE		1.66	0.50	2.15	
With an equivalent fuel economy of (liter/100km) HHV:	**7.30**				
Gasoline FCV with on-board reforming		2.66	0.39	3.04	5.98
Untaxed Gasoline FCV with on-board reforming		1.39	0.39	1.77	
With an equivalent fuel economy of (liter/100km) HHV:	**6.11**				
*** Taxed methanol FCV with on-board reforming**		2.50	0.32	2.82	5.98
Methanol FCV with on-board reforming		1.63	0.32	1.95	
With an equivalent fuel economy of (liter/100km) HHV:	**4.19**				
*** Taxed hydrogen FCV from decentralized SMR**		2.11	0.17	2.28	5.98
Hydrogen FCV from decentralized SMR		1.48	0.17	1.65	
With an equivalent fuel economy of (liter/100km) HHV:	**3.02**				
*** Taxed hydrogen FCV from decentralized electrolysis**		2.82	0.04	2.86	5.98
Hydrogen FCV from decentralized electrolysis		2.19	0.04	2.23	
With an equivalent fuel economy of (liter/100km) HHV:	**3.02**				

* Assumes methanol and hydrogen are taxed at the same rate per unit energy (HHV) as gasoline

Capital + O&M (Operation and Maintenance) Cost

	Variable		Units	Value
1)	C_C	Annual capital and O&M cost	$/yr	17699
2)	C_{cap}	Total installed capital cost of H2 dispensing station: electrolyzer, compressor, H2 storage and associated controls	$	70428
3)	e	Capital cost of electrolyzer	$	28931
4)	c	Capital cost of compressor	$	18767
5)	s	Capital cost of storage	$	15040
	x	Capital cost of balance of plant	$	7690
6)	CRF	Capital recovery factor	-	0.1841
7)	CRF_e	Effective capital recovery factor	-	0.2136
	op	Annual operating and maintenance costs	% of C_{cap}	**3.77**
			$/yr	2655
	ins	Annual insurance	% of C_{cap}	**0**
			$/yr	0
	t	Annual property taxes	% of C_{cap}	**0**
			$/yr	0

1) $C_c = C_{cap}(CRF_e + op + ins + t) + CRF\left(\sum_i \frac{E_i(n)}{(1+d)^n}\right)$

2) $C_{cap} = (e + c + s + x)$

3) $e = e_u * \frac{kout}{\eta_u}$

4) $c = c_u * k_{out}$

5) $s = s_u * \frac{Y}{365} * \frac{D}{A}$

6) $CRF = \frac{d}{1-(1+d)^{-N}}$

7) $CRF_e = CRF$ for home appliance case $CRF_e = \frac{\left\{CRF - \frac{T_b}{N}\right\}}{1-T_b}$ for business case

8)	Q_{H2max}	Maximum H2 flow from electrolyzer	Nm^3/h	26.493
9)	k_{out}	Maximum required H2 power output (HHV) from electrolyzer	kW	93.83

8) $$Q_{H2\max} = \left(\frac{Y}{365*24}\right)*11.126*\frac{R_{pd}}{f}$$

9) $$k_{out} = Q_{H2\max}*3.5418$$

η_U	Useful energy efficiency of electrolyzer (excluding compression)	%	79.5
	(Heating value of H2 output (HHV) @ 25° C)		
	(Energy input e- + NG (HHV))		
R_{pd}	Ratio of peak H2 production to average demand	-	1.1
f	Capacity factor (average use [hours per day] / 24h)	-	0.75
e_u	Unit cost of electrolyzer per kW_e	$\$/kW_e$	245
c_u	Unit cost of compressor per kW_{out} of H2 (HHV)	$\$/kW_{out}$ (HHV)	200
D	Equivalent number of days of storage	days	0.432
A	Available fraction of stored hydrogen	-	0.4
s_u	Storage capital cost per kg of stored H2 (HHV)	$\$/kg\ H_2$	357.4
x	Capital cost of balance of plant	$	7690

If treated as a home appliance, enter 1
If treated as a business investment, enter 2 — 2

10)

d	Discount rate	%	12.97
N	Economic recovery period	years	10
i_m	Mortgage interest rate (if financed as a home appliance)	%	9.0
T_p	Personal tax rate of home owner	%	35.0
i	General inflation rate	%	2.7
r	After-tax real rate of return on investment (for business case) (in constant dollars)	%	10.0
T_b	Business tax rate	%	26.0

10) $d = i_m * (1 - T_p)$ for home case
$d = r + i(1 + r)$ for business case

Extraordinary expenses

E_1	extraordinary expense 1	$	0
n_1	year in which extraordinary expense 1 occurs	-	
E_2	extraordinary expense 2	$	0
n_2	year in which extraordinary expense 2 occurs	-	
E_3	extraordinary expense 3	$	0
n_3	year in which extraordinary expense 3 occurs	-	
E_4	extraordinary expense 4	$	0
n_4	year in which extraordinary expense 4 occurs	-	
E_5	extraordinary expense 5	$	0
n_5	year in which extraordinary expense 5 occurs	-	

Energy Cost

Variable		Units	Value
C_e	Annual energy cost	$/yr	24401
C_{el}	Annual cost of energy for electrolyzer	$/yr	21155
C_{comp}	Annual cost of energy for compressor	$/yr	3246

$$C_e = C_{el} + C_{comp}$$

$$C_{el} = \frac{k_{elth}}{\eta_e} \times Y \times \left[(1-\alpha)P_{e^-} + 0.0036\alpha P_{NG}\right]$$

$$C_{comp} = \frac{k_{cth}}{\eta_c} \times Y \times P_{e^-}$$

K	Specific energy required by electrolyzer and compressor	kWh/kg H2	57.2
k_{elth}	Specific theoretical energy required by electrolyzer (excluding compressor)	kWh/kg H2	39.7
	(Assuming no heat recovery from product gases)		
k_{el}	Theoretical energy required to electrolyze water	kWh/kg H2	39.1
$k_{el\Delta G}$	Required change in Gibbs free energy	kWh/kg H2	31.7
$k_{elT\Delta S}$	Required heat for electrolysis	kWh/kg H2	7.4
k_{hH2O}	Theoretical energy required to heat feed-water to electrolysis temperature	kWh/kg H2	0.5
	(Includes energy for vaporization at Temperature > or = 100 C)		
η_e	Energy efficiency of electrolyzer	%	80.0
	~~{Specific theoretical energy required by electrolyzer}~~		
	{Specific energy input (e- + NG (HHV))}		
k_{cth}	Specific theoretical energy required for compression	kWh/kg H2	5.7
η_c	Compressor efficiency (with respect to adiabatic compression)	%	75
P_{e^-}	Electricity price	$/kWh	0.030
P_{NG}	Natural gas price	$/GJ	3.00
		$/kWh HHV	0.011
α	Fraction of energy required for electrolysis provided by NG	-	0

$$K = \frac{k_{elth}}{\eta_e} + \frac{k_{cth}}{\eta_c}$$

$$k_{elth} = 26.589 \times \left[E_{HHV}(T) + \frac{3RT}{4F} \ln P_i \right]$$ or equivalent $$k_{elth} = k_{el} + k_{hH2O}$$

$$k_{el} = 26.589 \times \left[\frac{\Delta H(T)}{2F} + \frac{3RT}{4F} \ln P_i \right]$$ or equivalent $$k_{el} = k_{el\Delta G} + k_{elT\Delta S}$$

$$k_{el} = 26.589 \times \left[\frac{\Delta G(T)}{2F} + \frac{3RT}{4F} \ln P_i \right]$$

$$k_{elT\Delta S} = 26.589 \times \left[\frac{\Delta H(T) - \Delta G(T)}{2F} \right]$$

$$k_{hH2O} = 26.589 \times \left[E_{HHV}(T) - \frac{\Delta H(T)}{2F} \right]$$

$$k_{cth} = 1.378 \times 10^{-4} RT \times \left(\frac{\gamma}{\gamma - 1} \right) \times \left[\left(\frac{P_o}{P_i} \right)^{\frac{\gamma-1}{\gamma}} - 1 \right]$$

T	Electrolysis temperature	°C	**70**
		K	343
P_i	Electrolysis pressure (also inlet pressure to compressor)	bar	**1**
P_o	Outlet pressure from compressor (also hydrogen storage pressure)	bar	**413.7**

Greenhouse Gas Related Relative Cost/Saving

Variable		Units	Value
C_{GHG1}	Relative annual cost/saving in terms of GHG (with respect to gasoline ICE)	$/yr	-8833
C_{GHG2}	Relative annual cost/saving in terms of GHG (with respect to gasoline FCV with on-board processing)	$/yr	-6721
C_{GHG3}	Relative annual cost/saving in terms of GHG (with respect to methanol FCV with on-board processing)	$/yr	-5530
C_{GHG4}	Relative annual cost/saving in terms of GHG (with respect to hydrogen FCV from decentralized SMR)	$/yr	-2630
$C_{GHGalt1}$	Value of GHG emissions from alternative 1 (Gasoline ICE)	$/km driven	0.00496
$C_{GHGalt2}$	Value of GHG emissions from alternative 2 (Gasoline FCV with on-board processing)	$/km driven	0.00386
$C_{GHGalt3}$	Value of GHG emissions from alternative 3 (Methanol FCV with on-board processing)	$/km driven	0.00324
$C_{GHGalt4}$	Value of GHG emissions from alternative 4 (Hydrogen FCV from decentralized SMR)	$/km driven	0.00173
C_{GHGel}	Value of GHG emissions from electrolysis	$/km driven	0.00036
C_{GHGkg}	Value of GHG emissions from electrolysis per kg of H2	$/kg H2	0.04854
E_{CO2}	Evaluation of CO2 equivalent emissions	US$/ton CO_2	20
Location		**Vancouver**	1
	For Vancouver, Canada, enter **1** For Los Angeles,USA, enter **2** For Paris, France, enter **3** For another location enter **4** (Other location, specified in worksheet "Site-Specific Info")		

Explanation of Cells Background Color

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🟨	Yellow cells identify interactive input cells.
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Summary of Input Variables

1) Need for Hydrogen Fuel

Variable			Units	Value
V	Number of vehicles served by station		-	100
M	Average annual mileage per vehicle		km/yr	19200
f_e	Average fuel economy		km/kg H2	135

2) Variables Influencing Capital + O&M Cost

R_{pd}	Ratio of peak H2 production to average demand	-	1.1
f	Capacity factor (average use [hours per day] / 24h)	-	0.75
e_u	Unit cost of electrolyzer per kW_e	$\$/kW_e$	245.00
c_u	Unit cost of compressor per kW_{out} of H2 (HHV)	$\$/kW_{out}$ (HHV)	200
D	Equivalent number of days of storage	days	0.432
A	Available fraction of stored hydrogen	-	0.4
s_u	Storage capital cost per kg of stored H2 (HHV)	$\$/kg\ H_2$	357.4
x	Capital cost of balance of plant	$	7690

Variables Involved in Financing the Electrolysis Station

If treated as a home appliance, enter 1

	If treated as a business investment, enter 2		2	
N	Economic recovery period	years	10	
i_m	Mortgage interest rate (if financed as an appliance)	%	9.0	for home appliance case
T_p	Personal tax rate of home owner	%	35.0	for home appliance case
i	General inflation rate	%	2.7	for business case
r	After-tax real rate of return on investment (in constant dollars)	%	10.0	for business case
T_b	Business tax rate	%	26.0	for business case

Greenhouse Gas Related Relative Cost/Saving

Variable		Units	Value
C_{GHG1}	Relative annual cost/saving in terms of GHG (with respect to gasoline ICE)	\$/yr	-8833
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E_{CO2}	Evaluation of CO2 equivalent emissions	US\$/ton CO_2	20
Location		**Vancouver**	**1**

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Summary of Input Variables

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2) Variables Influencing Capital + O&M Cost

R_{pd}	Ratio of peak H2 production to average demand	-	**1.1**
f	Capacity factor (average use [hours per day] / 24h)	-	**0.75**
e_u	Unit cost of electrolyzer per kW_e	$\$/kW_e$	**245.00**
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D	Equivalent number of days of storage	days	**0.432**
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s_u	Storage capital cost per kg of stored H2 (HHV)	$\$/kg\ H_2$	**357.4**
x	Capital cost of balance of plant	$	**7690**

Variables Involved in Financing the Electrolysis Station

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If treated as a business investment, enter 2 **2**

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i	General inflation rate	%	**2.7**	for business case
r	After-tax real rate of return on investment (in constant dollars)	%	**10.0**	for business case
T_b	Business tax rate	%	**26.0**	for business case

O&M Cost

op	Annual operating and maintenance costs	% of Ccap	**3.77**	as a percentage of the total
ins	Annual insurance	% of Ccap	**0**	installed capital cost of the
t_p	Annual property taxes	% of Ccap	**0**	electrolytic hydrogen refuelling station

Extraordinary expenses

E_1	extraordinary expense 1	$	**0**
n_1	year in which extraordinary expense 1 occurs	-	**0**
E_2	extraordinary expense 2	$	**0**
n_2	year in which extraordinary expense 2 occurs	-	**0**
E_3	extraordinary expense 3	$	**0**
n_3	year in which extraordinary expense 3 occurs	-	**0**
E_4	extraordinary expense 4	$	**0**
n_4	year in which extraordinary expense 4 occurs	-	**0**
E_5	extraordinary expense 5	$	**0**
n_5	year in which extraordinary expense 5 occurs	-	**0**

3) Variables Influencing Energy Cost

η_e	Energy efficiency of electrolyzer {Total theoretical energy required by electrolyzer} {Energy input e- + NG (HHV)}	%	**80**
η_c	Compressor efficiency (with respect to adiabatic compression)	%	**75**
P_{e^-}	Electricity price	$/kWh	**0.030**
P_{NG}	Natural gas price	$/GJ	**3.00**
α	Fraction of energy required for electrolysis provided by NG	-	**0**
T	Electrolysis temperature	°C	**70**
P_i	Electrolysis pressure (also inlet pressure to compressor)	bar	**1**
P_o	Outlet pressure from compressor (also hydrogen storage pressure)	bar	**413.7**

4) Variables Influencing the Greenhouse Gas "Added Cost/Saving" Component

Treatment of C_{GHG} (added cost(+) or saving (-) due to GHG evaluation)	0
To exclude the impact of C_{GHG}, on the unit cost of H2 (U)	enter 0
To include C_{GHG} considering the alternative option:	
Gasoline ICE,	enter 1
Gasoline FCV with on-board reforming,	enter 2
Methanol FCV with on-board reforming,	enter 3
Hydrogen FCV from decentralized SMR,	enter 4

Monetary Evaluation of Greenhouse Gas Emissions

E_{CO2}	Evaluation of CO2 equivalent emissions	US$/ton CO_2	20

Fuel Economy of Other Fuel Options

Option	liter of gasoline equiv. (HHV) per 100 km
Gasoline ICE	7.30
Gasoline FCV *on-board reforming*	6.11
Methanol FCV *on-board reforming*	4.19
Hydrogen FCV from decentralized SMR	3.02

Base Case for Each Other Fuel Option

Option	GHG emissions g ($CO_{2\,equiv.}$)/km driven	liter of gasoline equiv. (HHV) per 100 km
Gasoline ICE	248	7.30
Gasoline FCV on-board reforming	193	6.11
Methanol FCV on-board reforming	162	4.19
Hydrogen FCV from decentralized SMR	80	2.79

Location

	Vancouver	1

For Vancouver, Canada, enter **1**
For Los Angeles,USA, enter **2**
For Paris, France, enter **3**
For another location enter **4**
(Other location, specified in worksheet "Site-Specific Info")

5) Site-Specific Information

Affecting Comparison with Other Fuelling Options

Item	Units	Location			
		Vancouver Canada	Los Angeles United States	Paris France	**Other Location Country**
Gasoline retail price	$/liter	**0.44**	**0.37**	**1.21**	**0.96**
Tax on gasoline	$/liter	**0.21**	**0.10**	**0.95**	**0.54**
Untaxed Methanol retail price	$/liter	**0.20**	**0.20**	**0.20**	**0.20**
Hydrogen from decentralized SMR	$/kg H2	**2.00**	**2.00**	**2.00**	**2.00**

Affecting Greenhouse Gas Added Cost or Saving

Electricity Mix Vancouver

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_{2\ \text{equiv.}}$)/kWh delivere	g (CO$_{2\ \text{equiv.}}$)/kWh delivered
	0	Coal	1071	0
	1	Oil	855	9
	5	Natural Gas	605	30
	0	Nuclear	16	0
	91	Hydro	4	4
	0	Wind	36	0
	0	Solar	193	0
	3	Other	0	0
Total	100			42

Electricity Mix Los Angeles

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_{2\ \text{equiv.}}$)/kWh delivere	g (CO$_{2\ \text{equiv.}}$)/kWh delivered
	11	Coal	1071	118
	0	Oil	855	0
	50	Natural Gas	605	303
	16	Nuclear	16	3
	10	Hydro	4	0
	1.5	Wind	36	1
	0.5	Solar	193	1
	11	Other	0	0
Total	100			425

Electricity Mix Paris

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_2$ $_{equiv.}$)/kWh delivere	g (CO$_2$ $_{equiv.}$)/kWh delivered
	3	Coal	1071	32
	0	Oil	855	0
	1	Natural Gas	605	6
	82	Nuclear	16	13
	14	Hydro	4	1
	0	Wind	36	0
	0	Solar	193	0
	0	Other	0	0
Total	100			52

Electricity Mix: (Other location)

	Mix	Source	GHG emissions	GHG emissions contribution
	%	-	(CO$_2$ $_{equiv.}$)/kWh delivere	g (CO$_2$ $_{equiv.}$)/kWh delivered
	70	Coal	1071	750
	0	Oil	855	0
	20	Natural Gas	605	121
	0	Nuclear	16	0
	10	Hydro	4	0
	0	Wind	36	0
	0	Solar	193	0
	0	Other	0	0
Total	100			871

Total Cost of Electrolytic Hydrogen

	Variable		Units	Value
1)	U	Unit cost of H2	\$/kg	2.96
2)	C	Total annual cost of H2	\$/yr	42100
3)	Y	Annual H2 production from station	kg/yr	14222.2
	C_c	Annual capital and O&M cost	\$/yr	17699
	C_e	Annual energy cost	\$/yr	24401
	C_{GHG}	Annual added cost(+) or saving (-) due to GHG evaluation	\$/yr	0

Compared to: No comparison

1) $U = \frac{C}{Y}$

2) $C = C_c + C_e(+C_{GHG})$ **

Because C_{GHG} is a relative term depending on the alternative option considered, it is possible to include or exclude C_{GHG} in the total annual cost of H2

Treatment of C_{GHG}

	0
To exclude the impact of C_{GHG}, on the unit cost of H2 (U)	enter **0**
To include C_{GHG} considering the alternative option:	
Gasoline ICE,	enter **1**
Gasoline FCV with on-board reforming,	enter **2**
Methanol FCV with on-board reforming,	enter **3**
Hydrogen FCV from decentralized SMR,	enter **4**

3) $Y = V\frac{M}{f_e}$

	V	Number of vehicles served by station	-	**100**
4)	**M**	Average annual mileage per vehicle	km/yr	**19200**
5)	**f_e**	Average fuel economy	km/kg H2	**135**

4) If necessary, the required annual hydrogen production (Y) could be calculated using the specific mileage (M_i) and fuel economy ($(f_e)_i$) of the various vehicles to be served by the station:

$$Y = V\frac{M}{f_e} = \sum_{i=1}^{V}\frac{M_i}{(f_e)_i}$$

5) The fuel economy of a vehicle (f_e), in km driven per kg of H2, can be calculated:

A) Directly from the average energy input required (HHV) per km driven

f_e [km/kg H2] = ***energy required (HHV)*** *[kJ/km]* / ***141,860*** *[kJ/kg H2]*

B) From the equivalent fuel economy if gasoline (HHV) were used,
either in equivalent liters of gasoline per 100 km driven

f_e [km/kg H2] = **407.83 / Lphkm** (using HHV values for both gasoline and H2)

or in miles per US gallon of gasoline equivalent (mpgge)

f_e [km/kg H2] = **1.7339 * mpgge** (using HHV values for both gasoline and H2)

Lphkm: fuel economy in liters of gasoline equivalent (HHV) per 100 km
mpgge: fuel economy in miles per US gallon of gasoline equivalent (HHV)

For consistence in this research, the higher-heating-value is always the one used for gasoline methanol and hydrogen when using equivalent fuel economy.

Total Cost of Electrolytic Hydrogen

	$/kg H2	$/lb H2	$/GJ HHV	%
Cost of energy	1.72	0.78	12.09	58
Cost of O&M	0.19	0.08	1.32	6
Cost of storage	0.23	0.10	1.59	8
Cost of electrolyzer	0.43	0.20	3.06	15
Cost of compressor	0.28	0.13	1.99	10
Cost of bop	0.12	0.05	0.81	4
Cost of extraordinary expenses	0.00	0.00	0.00	0
Total	**2.96**	**1.34**	**20.87**	**100**

Relative cost/saving due to GHG emissions evaluation

Assuming a GHG evaluation of:	20 US$/tonne CO_2 equivalent

Compared to:

Added cost (positive) or saving (negative)

Gasoline ICE

		$/kg H2	$/lb H2	$/GJ HHV	%
With an equivalent fuel economy of (liter/100km) HHV*:	**7.30**	-0.62	-0.28	-4.38	-21
Total		**2.34**	**1.06**	**16.49**	**79**

Gasoline FCV with on-board reforming

With an equivalent fuel economy of (liter/100km) HHV*:	**6.11**	-0.47	-0.21	-3.33	-16
Total		**2.49**	**1.13**	**17.54**	**84**

Methanol FCV with on-board reforming

With an equivalent fuel economy of (liter/100km) HHV*:	**4.19**	-0.39	-0.18	-2.74	-13
Total		**2.57**	**1.17**	**18.13**	**87**

Hydrogen FCV from decentralized SMR

With an equivalent fuel economy of (liter/100km) HHV*:	**3.02**	-0.18	-0.08	-1.30	-6
Total		**2.78**	**1.26**	**19.56**	**94**

Cost Comparison with Other Fuelling Options

		Fuel cost to consumer	Including effect of GHG emission evaluation		Tax on fuel Vancouver $/GJ-HHV
			Added cost	Total	
		¢/km driven	¢/km driven		
Gasoline ICE		3.18	0.50	3.67	5.98
Untaxed Gasoline ICE		1.66	0.50	2.15	
With an equivalent fuel economy of (liter/100km) HHV:	**7.30**				
Gasoline FCV with on-board reforming		2.66	0.39	3.04	5.98
Untaxed Gasoline FCV with on-board reforming		1.39	0.39	1.77	
With an equivalent fuel economy of (liter/100km) HHV:	**6.11**				
*** Taxed methanol FCV with on-board reforming**		2.50	0.32	2.82	5.98
Methanol FCV with on-board reforming		1.63	0.32	1.95	
With an equivalent fuel economy of (liter/100km) HHV:	**4.19**				
*** Taxed hydrogen FCV from decentralized SMR**		2.11	0.17	2.28	5.98
Hydrogen FCV from decentralized SMR		1.48	0.17	1.65	
With an equivalent fuel economy of (liter/100km) HHV:	**3.02**				
*** Taxed hydrogen FCV from decentralized electrolysis**		2.82	0.04	2.86	5.98
Hydrogen FCV from decentralized electrolysis		2.19	0.04	2.23	
With an equivalent fuel economy of (liter/100km) HHV:	**3.02**				

* Assumes methanol and hydrogen are taxed at the same rate per unit energy (HHV) as gasoline

Capital + O&M (Operation and Maintenance) Cost

	Variable		Units	Value
1)	C_C	Annual capital and O&M cost	\$/yr	17699
2)	C_{cap}	Total installed capital cost of H2 dispensing station:	\$	70428
		electrolyzer, compressor, H2 storage and associated controls		
3)	e	Capital cost of electrolyzer	\$	28931
4)	c	Capital cost of compressor	\$	18767
5)	s	Capital cost of storage	\$	15040
	x	Capital cost of balance of plant	\$	7690
6)	CRF	Capital recovery factor	-	0.1841
7)	CRF_e	Effective capital recovery factor	-	0.2136
	op	Annual operating and maintenance costs	% of C_{cap}	**3.77**
			\$/yr	2655
	ins	Annual insurance	% of C_{cap}	**0**
			\$/yr	0
	t	Annual property taxes	% of C_{cap}	**0**
			\$/yr	0

1) $C_c = C_{cap}(CRF_e + op + ins + t) + CRF\left(\sum_i \frac{E_i(n)}{(1+d)^n}\right)$

2) $C_{cap} = (e + c + s + x)$

3) $e = e_u * \frac{kout}{\eta_u}$

4) $c = c_u * k_{out}$

5) $s = s_u * \frac{Y}{365} * \frac{D}{A}$

6) $CRF = \frac{d}{1-(1+d)^{-N}}$

7) $CRF_e = CRF$ for home appliance case $CRF_e = \frac{\left\{CRF - \frac{T_b}{N}\right\}}{1-T_b}$ for business case

8)	Q_{H2max}	Maximum H2 flow from electrolyzer	Nm^3/h	26.493
9)	k_{out}	Maximum required H2 power output (HHV) from electrolyzer	kW	93.83

8) $Q_{H2\max} = \left(\frac{Y}{365*24}\right)*11.126*\frac{R_{pd}}{f}$

9) $k_{out} = Q_{H2\max}*3.5418$

η_U	Useful energy efficiency of electrolyzer (excluding compression) (Heating value of H2 output (HHV) @ 25° C) (Energy input e- + NG (HHV))	%	79.5
R_{pd}	Ratio of peak H2 production to average demand	-	1.1
f	Capacity factor (average use [hours per day] / 24h)	-	0.75
e_u	Unit cost of electrolyzer per kW_e	$\$/kW_e$	245
c_u	Unit cost of compressor per kW_{out} of H2 (HHV)	$\$/kW_{out}$ (HHV)	200
D	Equivalent number of days of storage	days	0.432
A	Available fraction of stored hydrogen	-	0.4
s_u	Storage capital cost per kg of stored H2 (HHV)	$\$/kg\ H_2$	357.4
x	Capital cost of balance of plant	$	7690

If treated as a home appliance, enter 1
If treated as a business investment, enter 2 | 2

10)	d	Discount rate	%	12.97
	N	Economic recovery period	years	10
	i_m	Mortgage interest rate (if financed as a home appliance)	%	9.0
	T_p	Personal tax rate of home owner	%	35.0
	i	General inflation rate	%	2.7
	r	After-tax real rate of return on investment (for business case) (in constant dollars)	%	10.0
	T_b	Business tax rate	%	26.0

10) $d = i_m * (1 - T_p)$ for home case

$d = r + i(1 + r)$ for business case

Extraordinary expenses

E_1	extraordinary expense 1	$	0
n_1	year in which extraordinary expense 1 occurs	-	
E_2	extraordinary expense 2	$	0
n_2	year in which extraordinary expense 2 occurs	-	
E_3	extraordinary expense 3	$	0
n_3	year in which extraordinary expense 3 occurs	-	
E_4	extraordinary expense 4	$	0
n_4	year in which extraordinary expense 4 occurs	-	
E_5	extraordinary expense 5	$	0
n_5	year in which extraordinary expense 5 occurs	-	

Energy Cost

Variable		Units	Value
C_e	Annual energy cost	$/yr	24401
C_{el}	Annual cost of energy for electrolyzer	$/yr	21155
C_{comp}	Annual cost of energy for compressor	$/yr	3246

$$C_e = C_{el} + C_{comp}$$

$$C_{el} = \frac{k_{elth}}{\eta_e} \times Y \times \left[(1-\alpha)P_{e^-} + 0.0036\alpha P_{NG}\right]$$

$$C_{comp} = \frac{k_{cth}}{\eta_c} \times Y \times P_{e^-}$$

K	Specific energy required by electrolyzer and compressor	kWh/kg H2	57.2
k_{elth}	Specific theoretical energy required by electrolyzer (excluding compressor)	kWh/kg H2	39.7
	(Assuming no heat recovery from product gases)		
k_{el}	Theoretical energy required to electrolyze water	kWh/kg H2	39.1
$k_{el\Delta G}$	Required change in Gibbs free energy	kWh/kg H2	31.7
$k_{elT\Delta S}$	Required heat for electrolysis	kWh/kg H2	7.4
k_{hH2O}	Theoretical energy required to heat feed-water to electrolysis temperature	kWh/kg H2	0.5
	(Includes energy for vaporization at Temperature > or = 100 C)		
η_e	Energy efficiency of electrolyzer	%	80.0
	~~{Specific theoretical energy required by electrolyzer}~~		
	{Specific energy input (e- + NG (HHV))}		
k_{cth}	Specific theoretical energy required for compression	kWh/kg H2	5.7
η_c	Compressor efficiency (with respect to adiabatic compression)	%	75
P_{e^-}	Electricity price	$/kWh	0.030
P_{NG}	Natural gas price	$/GJ	3.00
		$/kWh HHV	0.011
α	Fraction of energy required for electrolysis provided by NG	-	0

$$K = \frac{k_{elth}}{\eta_e} + \frac{k_{cth}}{\eta_c}$$

$$k_{elth} = 26.589 \times \left[E_{HHV}(T) + \frac{3RT}{4F} \ln P_i \right]$$ or equivalent $$k_{elth} = k_{el} + k_{hH2O}$$

$$k_{el} = 26.589 \times \left[\frac{\Delta H(T)}{2F} + \frac{3RT}{4F} \ln P_i \right]$$ or equivalent $$k_{el} = k_{el\Delta G} + k_{elT\Delta S}$$

$$k_{el} = 26.589 \times \left[\frac{\Delta G(T)}{2F} + \frac{3RT}{4F} \ln P_i \right]$$

$$k_{elT\Delta S} = 26.589 \times \left[\frac{\Delta H(T) - \Delta G(T)}{2F} \right]$$

$$k_{hH2O} = 26.589 \times \left[E_{HHV}(T) - \frac{\Delta H(T)}{2F} \right]$$

$$k_{cth} = 1.378 \times 10^{-4} RT \times \left(\frac{\gamma}{\gamma - 1} \right) \times \left[\left(\frac{P_o}{P_i} \right)^{\frac{\gamma-1}{\gamma}} - 1 \right]$$

T	Electrolysis temperature	°C	**70**
		K	343
P_I	Electrolysis pressure (also inlet pressure to compressor)	bar	**1**
P_o	Outlet pressure from compressor (also hydrogen storage pressure)	bar	**413.7**

Greenhouse Gas Related Relative Cost/Saving

Variable		Units	Value
C_{GHG1}	Relative annual cost/saving in terms of GHG (with respect to gasoline ICE)	$/yr	-8833
C_{GHG2}	Relative annual cost/saving in terms of GHG (with respect to gasoline FCV with on-board processing)	$/yr	-6721
C_{GHG3}	Relative annual cost/saving in terms of GHG (with respect to methanol FCV with on-board processing)	$/yr	-5530
C_{GHG4}	Relative annual cost/saving in terms of GHG (with respect to hydrogen FCV from decentralized SMR)	$/yr	-2630
$C_{GHGalt1}$	Value of GHG emissions from alternative 1 (Gasoline ICE)	$/km driven	0.00496
$C_{GHGalt2}$	Value of GHG emissions from alternative 2 (Gasoline FCV with on-board processing)	$/km driven	0.00386
$C_{GHGalt3}$	Value of GHG emissions from alternative 3 (Methanol FCV with on-board processing)	$/km driven	0.00324
$C_{GHGalt4}$	Value of GHG emissions from alternative 4 (Hydrogen FCV from decentralized SMR)	$/km driven	0.00173
C_{GHGel}	Value of GHG emissions from electrolysis	$/km driven	0.00036
C_{GHGkg}	Value of GHG emissions from electrolysis per kg of H2	$/kg H2	0.04854
E_{CO2}	Evaluation of CO2 equivalent emissions	US$/ton CO_2	20
Location		**Vancouver**	1

For Vancouver, Canada, enter **1**
For Los Angeles,USA, enter **2**
For Paris, France, enter **3**
For another location enter **4**
(Other location, specified in worksheet "Site-Specific Info")

$$K = \frac{k_{elth}}{\eta_e} + \frac{k_{cth}}{\eta_c}$$

$$k_{elth} = 26.589 \times \left[E_{HHV}(T) + \frac{3RT}{4F} \ln P_i \right]$$ or equivalent $$k_{elth} = k_{el} + k_{hH2O}$$

$$k_{el} = 26.589 \times \left[\frac{\Delta H(T)}{2F} + \frac{3RT}{4F} \ln P_i \right]$$ or equivalent $$k_{el} = k_{el\Delta G} + k_{elT\Delta S}$$

$$k_{el} = 26.589 \times \left[\frac{\Delta G(T)}{2F} + \frac{3RT}{4F} \ln P_i \right]$$

$$k_{elT\Delta S} = 26.589 \times \left[\frac{\Delta H(T) - \Delta G(T)}{2F} \right]$$

$$k_{hH2O} = 26.589 \times \left[E_{HHV}(T) - \frac{\Delta H(T)}{2F} \right]$$

$$k_{cth} = 1.378 \times 10^{-4} RT \times \left(\frac{\gamma}{\gamma - 1} \right) \times \left[\left(\frac{P_o}{P_i} \right)^{\frac{\gamma-1}{\gamma}} - 1 \right]$$

T	Electrolysis temperature	°C	**70**
		K	343
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Greenhouse Gas Related Relative Cost/Saving

Variable		Units	Value
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C_{GHG4}	Relative annual cost/saving in terms of GHG (with respect to hydrogen FCV from decentralized SMR)	\$/yr	-2630
$C_{GHGalt1}$	Value of GHG emissions from alternative 1 (Gasoline ICE)	\$/km driven	0.00496
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$C_{GHGalt4}$	Value of GHG emissions from alternative 4 (Hydrogen FCV from decentralized SMR)	\$/km driven	0.00173
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C_{GHGkg}	Value of GHG emissions from electrolysis per kg of H2	\$/kg H2	0.04854
E_{CO2}	Evaluation of CO2 equivalent emissions	US\$/ton CO_2	20
Location		**Vancouver**	1

For Vancouver, Canada, enter **1**
For Los Angeles,USA, enter **2**
For Paris, France, enter **3**
For another location enter **4**
(Other location, specified in worksheet "Site-Specific Info")

GHG emissions associated with other fueling options

Option	GHG emissions	liter of gasoline	mile per US gallon
-	g ($CO_{2\ equiv.}$)/km driven	equiv. (HHV) per 100 km	of gasoline equiv. (HHV)
Gasoline ICE	248	7.30	32.2
Gasoline FCV on-board reforming	193	6.11	38.5
Methanol FCV on-board reforming	162	4.19	56.2
Hydrogen FCV from decentralized SMR	86	3.02	77.9

Base case for each other fuel option

	Option	GHG emissions	liter of gasoline	mile per US gallon
	-	g ($CO_{2\ equiv.}$)/km driven	equiv. (HHV) per 100 km	of gasoline equiv. (HHV)
*	Gasoline ICE	**248**	**7.30**	32.2
*	Gasoline FCV on-board reforming	**193**	**6.11**	38.5
*	Methanol FCV on-board reforming	**162**	**4.19**	56.2
*	Hydrogen FCV from decentralized SMR	**80**	**2.79**	84.2

• Data source: Pembina Institute for Appropriate Development, Climate Friendly Hydrogen: A Comparison of the Life-cycle Greenhouse Gas Emissions for Selected Fuel Cell Vehicle Hydrogen Production Systems, March 2000

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* Data source: Pembina Institute for Appropriate Development, Climate Friendly Hydrogen: A Comparison of the Life-cycle Greenhouse Gas Emissions for Selected Fuel Cell Vehicle Hydrogen Production Systems, March 2000

Site-Specific Information

Affecting Comparison with Other Fuelling Options

Item	Units	Location Vancouver Canada	Los Angeles United States	Paris France	**Other Location Country**
Gasoline retail price	$/liter	**0.44**	**0.37**	**1.21**	**0.96**
Gasoline untaxed	$/liter	0.23	0.27	0.26	0.42
Tax on gasoline	$/liter	**0.21**	**0.10**	**0.95**	**0.54**
Tax portion of gasoline cost	%	48	27	78	56
Untaxed Methanol retail price	$/liter	**0.20**	**0.20**	**0.20**	**0.20**
Hydrogen from decentralized SMR	$/kg H2	**2.00**	**2.00**	**2.00**	**2.00**

Affecting Capital Cost of Electrolysis

Variables of the model affected						
t	Annual property taxes	% of Ccap	1.5	1.5	1.5	1.5
i_m	Home owner mortgage interest rate	%	9.00	9.00	9.00	9.00
T_p	Personal tax rate of home owner	%	35.0	35.0	35.0	35.0
i	Inflation rate	%	2.7	2.7	2.7	2.7
r	After-tax real rate of return on investment	%	10.0	10.0	10.0	10.0
T_b	Business tax rate	%	26.0	26.0	26.0	26.0

Affecting Energy Cost of Electrolysis

P_{NG}	Natural gas retail price	$/GJ	5.50	7.00	9.00	14.00
P_{e^-}	Electricity average retail price	$/kWh	0.039	0.080	0.108	0.120
P_{e^-}	Electricity retail price off-peak	$/kWh	0.021	0.041	0.070	0.080
P_{e^-}, f	Electricity off-peak rate hours (0-24)	hr/day	18.0	16.0	12.0	12.0

Affecting Greenhouse Gas Added Cost or Saving

Electricity Mix Vancouver

	Mix	Source		GHG emissions	GHG emissions contribution
	%	-		g ($CO_{2\ equiv.}$)/kWh delivered	g ($CO_{2\ equiv.}$)/kWh delivered
	0	Coal		1071	0
	1	Oil		855	9
	5	Natural Gas		605	30
	0	Nuclear		16	0
	91	Hydro		4	4
	0	Wind		36	0
	0	Solar		193	0
	3	Other		0	0
Total	100				42

Electricity Mix Los Angeles

	Mix	Source		GHG emissions	GHG emissions contribution
	%	-		g ($CO_{2\ equiv.}$)/kWh delivered	g ($CO_{2\ equiv.}$)/kWh delivered
	11	Coal		1071	118
	0	Oil		855	0
	50	Natural Gas		605	303
	16	Nuclear		16	3
	10	Hydro		4	0
	1.5	Wind		36	1
	0.5	Solar		193	1
	11	Other		0	0
Total	100				425

Electricity Mix Paris

	Mix	Source		GHG emissions	GHG emissions contribution
	%	-		g ($CO_{2\ equiv.}$)/kWh delivered	g ($CO_{2\ equiv.}$)/kWh delivered
	3	Coal		1071	32
	0	Oil		855	0
	1	Natural Gas		605	6
	82	Nuclear		16	13
	14	Hydro		4	1
	0	Wind		36	0
	0	Solar		193	0
	0	Other		0	0
Total	100				52

Electricity Mix: Other Location

	Mix	Source		GHG emissions	GHG emissions contribution
	%	-		g ($CO_{2\ equiv.}$)/kWh delivered	g ($CO_{2\ equiv.}$)/kWh delivered
	70	Coal		1071	750
	0	Oil		855	0
	20	Natural Gas		605	121
	0	Nuclear		16	0
	10	Hydro		4	0
	0	Wind		36	0
	0	Solar		193	0
	0	Other		0	0
Total	100				871

Appendix D – Base Case Values for Sensitivity Analysis

Two main sources were used to select base case values for each parameter considered in the sensitivity analysis. The first one is the 1996 report by the Electrolyser Corporation (now Stuart Energy Systems) to Ford Motor [1]. This source offers the advantage of cost projections from an actual electrolyzer company. The second source is the 1995 report by Directed Technologies Inc. (DTI) [2]. Whenever these two sources are mentioned in the tables below they are referred to as "Stuart" and "DTI" respectively.

When the base case values are compared to values from "Stuart", they refer to the scenario that considers a fleet station comprising 10 HVRAs (hydrogen vehicle refuelling appliances), each designed to serve 4 FCVs, for a total of 40 fleet vehicles supported by the station, for an annual production of 25,000 HVRAs. Since the mileage of these fleet vehicles is 1.5 times higher than the one assumed for FCVs in this research, and their fuel economy about 40% lower, the same station size can be used for the base case of this research, supporting 100 FCVs. Further justification is given in the first table below. When the base case values are compared to values from "DTI", they refer to the scenario where an electrolytic hydrogen fleet station is financed by a utility.

The base case and range values for each parameter are presented in four separate tables. The first one considers the parameters that determine the hydrogen demand for the station. The other three tables respectively contain the parameters used in the three components of the cost model: "capital & O&M", "Energy", and "GHG added cost or saving".

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[1] Fairlie M. FCV Fuel Supply Infrastructure: The Electrolysis Option, Electrolyser, Ltd. Toronto, Canada, December, 1996, 105 p.

[2] Thomas C.E., Kuhn I.F. Jr. Electrolytic Hydrogen Production Infrastructure Options and Evaluation. Prepared for the National Renewable Energy Laboratory by Directed Technologies Inc. Report No. NREL/TP-463-7903, National Renewable Energy Laboratory, Colorado, U.S., 1995, 51 p.

Parameter		Units	Range considered	Base case
V	Number of vehicles supported	vehicles	2 – 1,000	100
Justifications	• The base case of $V = 100$ vehicles supported was selected arbitrarily, somewhere in the middle of the range considered. • The lower range value $V = 2$ correspond to a home electrolyzer supporting two FCVs. The upper range value $V = 1{,}000$ is of the same order as the average gasoline service station in the U.S., which serves 165 vehicles per day or about 1,150 weekly [1].			
M	Average mileage per vehicle	km/yr	-	19,200
Justifications	• The base case annual mileage used in this research (19,200 km/yr) reflects the average annual North American mileage for light-duty vehicles, and is identical to the value used by Stuart and DTI. For fleet vehicles however, Stuart and DTI both use an annual mileage that is 1.5 times higher (28,800 km/yr).			
f_e	Average fuel economy	km/ kg H_2	-	135
Justifications	• The base case fuel economy value selected (135 km/kg H_2) is similar to the one provided by Ballard Power Systems for a 5-seater Mercedes A-Class FCV [2]. The FCVs considered by Stuart had a fuel economy about 40% lower (80 km/kg) because they were based on a larger and heavier vehicle.			

Table D.1: Base case values and range for parameters used to determine the hydrogen demand of the fuelling station.

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[1] Fairlie M. FCV Fuel Supply Infrastructure: The Electrolysis Option, Electrolyser, Ltd. Toronto, Canada, December, 1996, 105 p.

[2] Pembina Institute for Appropriate Development, Climate-Friendly Hydrogen Fuel: A Comparison of the Life-cycle Greenhouse Gas Emissions for Selected Fuel Cell Vehicle Hydrogen Production Systems. Report written with support from The David Suzuki Foundation, March 2000, 44 p.

Parameter		Units	Range considered	Base case
R_{pd}	Ratio of peak H_2 production to average demand	-	1.1 – 1.5	1.2
Justifications	• DTI suggests designing for two standard deviations from the mean as a function of the number of vehicles supported by the station, following a Poisson distribution. DTI applied this rule to a 50-car fleet resulting in $R_{pd} = 1.28$. The same rule was applied for a 100-car fleet in the base case, giving $R_{pd} = 1.2$. • The same rule was also applied to a 1000-car fleet, giving $R_{pd} = 1.1$ for the lower range value. DTI selected $R_{pd} = 1.5$ arbitrarily for a two-car station. This analysis used the same value for the upper range value. • Stuart uses $R_{pd} = 1.6$ for fleet terminals up to 100 vehicles, and $R_{pd} = 2$ for a two-car station. However, much more storage capacity was planned by DTI, which effectively reduces the need for a large surge factor. The base case for this study also assumes high storage capacity			
f	Capacity factor	-	0.25 – 1	0.7
Justifications	• Base case value identical to the one used by DTI in their analysis. • The range corresponds to an operating time of 6 to 24 hours a day			
e_u	Electrolyzer unit cost	$\$/\text{kW}_e$	100 – 1,000	200
Justifications	• The base case value of $\$200/\text{kW}_e$ corresponds within 1% to the value used by DTI: $\$300/\text{kW}_{out}$ (LHV) at 67.5% efficiency (LHV-basis). It is also coherent with Stuart's estimate of about $\$140/\text{kW}_e$ at nominal hydrogen production capacity. This number is based on the combined cost of the electrolyzer and power system, considering the production of 25,000 HVRA units annually. • The lower range value of $\$100/\text{kW}_e$ was estimated simply as half of the base case unit cost. • The upper range value is representative of current estimates for electrolyzer station costs produced in small volumes. Stuart's cost estimate for the first 100 HVRA units is in the same range: $\$700/\text{kW}_e$ at nominal hydrogen production capacity. Other estimates for NEDO in Japan estimate the total cost of a single fuelling station based on PEM electrolysis at about $\$1{,}300/\ \text{kW}_e$ [1], while Norsk Hydro's estimate for the total cost of a fuelling station based on AWE is around $\$800/\text{kW}_e$.[2]			

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[1] New Energy and Industrial Technology Development Organization (NEDO). International Clean Energy Network Using Hydrogen Conversion (WE-NET): 1998 Annual Summary Report on Results. March, 1999. 135 p.

[2] Kloed C. "Challenges and Opportunities of Building-Up a Hydrogen Infrastructure". Presented at the Grove Symposium VII, London, UK, 9-12 September, 2001.

Parameter		Units	Range considered	Base case
C_u	Compressor and dispenser unit cost	$\$/kW_{out}$ – HHV	70 – 500	170
Justifications	• The base case value of $\$170/kW_{out}$ (HHV) compares with $\$125/kW_{out}$ (HHV) at nominal hydrogen production capacity in Stuart's report, and $\$97/kW_{out}$ (HHV) for DTI. The number calculated from Stuart's report is based on the combined cost of the compressor and hydrogen dispenser, considering the production of 25,000 HVRA units annually. • The range \$70 - $\$500/kW_{out}$ was determined arbitrarily, based on values found in the literature. The compressor and dispenser costs estimated by Stuart for the first 100 HVRA units correspond to $\$377/kW_{out}$ (HHV).			
S_u	Hydrogen storage unit cost	\$/kg H_2 storage capacity	50 - 500	200
Justifications	• The base case value of \$200/kg H_2 lies somewhere between the projected value used by DTI (\$132/kg H_2) for advanced carbon fiber tanks, and the value used by Stuart (\$357/kg H_2) based on commercially available tanks, considering the production of 25,000 HVRA units annually. • The upper range value is based on various sources in the literature that indicate prices for high-pressure storage tanks, generally in the range of \$300-500/kg H_2, but sometimes higher [1,2].			
D	Equivalent days of storage	days	2 – 11.4	2
Justifications	• The base case value $D = 2$ is identical to the one used by DTI for a fleet station. It allows for hydrogen delivery at a different time of the day than the production, and can accommodate a one-day shutdown of the station. • The upper range value $D = 11.4$ corresponds to the smallest electrolyzer station considered in this study, i.e. a personal appliance supporting the hydrogen needs of two FCVs. This value is obtained by assuming two FCV tanks' worth of usable hydrogen storage. This assumption is the same as the one suggested by DTI.			
A	Available fraction of stored hydrogen	-	0.4 – 1	0.5
Justifications	• The base case value $A = 0.5$ lies somewhere between the value of 0.4 used by Stuart and the value of 0.625 used by DTI to account for this storage limitation. • The lower range value is the same as the value used by Stuart, whereas the upper range value corresponds to the ideal case of 100% recovery of the stored hydrogen.			

...table continues next page.

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[1] Padro C.E.G., Putsche V. Survey of the Economics of Hydrogen Technologies, NICH Report No. TP-570-27079, National Renewable Energy Laboratory, Colorado, U.S., 1999, 57 p.

[2] Ogden J.M. "Prospects for Building a Hydrogen Energy Infrastructure". In Annual Review of Energy and the Environment, 1999, 24: 227-279.

Parameter		Units	Range considered	Base case
CRF_e	Capital recovery factor (effective)	-	0.0715 – 0.3280	0.1230
Justifications	• The base case value CRF_e = 0.1230 is identical to the value used by DTI for the scenario where the fuelling station is financed by a utility. The particular conditions to arrive to that value are also identical to those used by DTI, for the utility scenario. These conditions include: a discount rate of 8.9% (6% after correcting for inflation of 2.7%) and an economic life of 15 years. • The lower range value corresponds to the financing scenario by a home owner as a home mortgage, under the following conditions: mortgage rate of 9%, economic recovery period of 30 years, and a personal tax rate of 35% (assuming that interest payments are tax deductible). • The upper range value corresponds to the financing scenario by a business, under the following conditions: an expected real rate of return of 15%, after taxes (business taxes of 50%) and inflation (2.7%).			
op	Operation and maintenance	% of C_{cap}	0.5 – 4	2
Justifications	• The base case value of 2% of the station's installed capital cost is the same as the one used by DTI. • The lower and upper range values were determined arbitrarily. However, they do correspond more or less to the range of values presented by Stuart for the various station sizes, assuming production levels in the range of 25,000 HVRA units/ year.			
ins	Annual insurance	% of C_{cap}	0 – 3	1.5
Justifications	• The base case value of 1.5% of the capital cost is identical to the value used by DTI. • The lower and upper range values were determined arbitrarily.			
t	Annual property taxes	% of C_{cap}	0 – 3	0.5
Justifications	• The base case value of 1.5% of the capital cost is identical to the value used by DTI. • The lower and upper range values were determined arbitrarily.			
$E_i(n_i)$	Extraordinary expense E_i occurring in year n_i (i = 1,2,3...)	$	0 – 50% of C_{cap} every 5 years	0
Justifications	• Assuming there is no extraordinary expense (beside normal O&M costs) is identical to DTI and Stuart. The upper range value of an extraordinary expense of 50% of the installed capital cost corresponds to the replacement of major components like the electrolysis cells and the compressor every five years.			

Table D.2: Base case values and range for parameters used to calculate the "Capital and O&M" costs of the fuelling station.

Parameter		Units	Range considered	Base case
η_e	Energy efficiency of electrolyzer (HHV)	%	60 – 100	80
Justifications	• The base case value η_e = 80% (HHV-basis) is equivalent to the value used by DTI (67.5% LHV-basis). It is somewhat higher than the value of 71% (HHV or 60% LHV) used by Stuart for a small electrolyzer station. • The lower range value of 60% corresponds to an electrolyzer station substantially less efficient than the alkaline electrolyzers offered by Stuart. The upper range value of 100% corresponds to the theoretical case of a perfectly efficient electrolyzer.			
η_c	Compressor efficiency	%	30 – 100	75
Justifications	• The base case value η_c = 75% (adiabatic) is identical to the one used by DTI. It is calculated with respect to the theoretical requirement for adiabatic compression. If this same efficiency was expressed with respect to isothermal compression instead, it would have a value of 31% (isothermal), using the base case input and output pressure of the compressor of 2 bar and 414 bar respectively. • The lower range value was determined arbitrarily, whereas the upper range value of 100% corresponds to the theoretical case of a perfectly efficient compressor.			
P_{e-}	Electricity price	\$/kWh	0.01 – 0.07	0.03
Justifications	• The base case value of 3 US¢/kWh is the main value used by Stuart for off-peak electricity. It is also the reference value used by Thomas et al. (DTI) and Ogden in later studies. [1,2] • The range values were determined arbitrarily, but are representative of off-peak electricity rates in many regions of industrialized countries. The lower range value of 1 US¢/kWh is conceivable if clean electricity for electrolytic hydrogen is subsidized or if major developments occur in power generation technology.			
T	Electrolysis temperature	°C	70 – 1000	70
Justifications	• The base case value of 70 °C is typical of conventional alkaline water electrolysis (AWE), which is the technology used by Stuart. The upper range value corresponds to the temperature used in high-temperature electrolysis technology (HTE).			

…table continues next page.

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[1] Thomas C.E., James B.D., Lomax F.D. Jr, Kuhn I.F. Jr. "Fuel Options for the Fuel Cell Vehicle: Hydrogen, Methanol or Gasoline?" International Journal of Hydrogen Energy 25 (2000): 551-567.

[2] Ogden J.M. "Developing an Infrastructure for Hydrogen Vehicles: a Southern California Case Study". International Journal of Hydrogen Energy 24 (1999): 709-730.

Parameter		Units	Range considered	Base case
P_i	Electrolysis pressure (also inlet pressure to compressor)	bar	2 – 414	2
Justifications	• The base case value of 2 bar is identical to the value used by Stuart. The upper range value of 414 bar corresponds to the maximum storage pressure of 6,000 psi used by both Stuart and DTI. This very high operating pressure could conceivably be achieved, most likely with SPE technology.			
P_o	Outlet pressure from compressor (also hydrogen storage pressure)	bar	2 – 414	414
Justifications	• The base case value of 414 bar corresponds to the to the maximum storage pressure of 6,000 psi used by both Stuart and DTI. The range of values account for the possibility of storing hydrogen at a lower pressure (e.g. in metal hydrides).			
P_{NG}	Natural gas price	$/GJ (HHV)	3.00 – 8.00	3.00
Justifications	• The base case value of $3.00/GJ (HHV) corresponds to approximately $3.30/GJ (LHV), which is somewhere between the price of natural gas for on-site SMR assumed by Thomas et al. ($3.79/GJ (LHV)) and Ogden ($2.80/GJ (LHV)). [1,2] • The upper range value was determined arbitrarily, to account for possible variations in the market price of the natural gas.			
A	Fraction of energy required for electrolysis provided by natural gas (for NGASE)	-	0 – 1	0
Justifications	• The base case corresponds to the situation where 100% of the energy required by the electrolyzer station comes from electricity. • The upper range value corresponds to the case where 100% of the energy required by the electrolyzer station comes from natural gas. A new technology like NGASE (natural gas assisted steam electrolysis) would be then necessary to make possible this hypothetical case.			

Table D.3: Base case values and range for parameters used to calculate the "Energy" costs of the fuelling station.

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[1] Thomas C.E., James B.D., Lomax F.D. Jr, Kuhn I.F. Jr. "Fuel Options for the Fuel Cell Vehicle: Hydrogen, Methanol or Gasoline?" International Journal of Hydrogen Energy 25 (2000): 551-567.

[2] Ogden J.M. "Developing an Infrastructure for Hydrogen Vehicles: a Southern California Case Study". International Journal of Hydrogen Energy 24 (1999): 709-730.

Parameter		Units	Range considered	Base case
E_{CO2}	Monetary valuation of CO_2 emissions	$\$$/ton CO_2	0 – 50	0
Justifications	• The base case monetary valuation of CO_2 emissions is zero, since the base case does not consider any influence from the greenhouse gas (GHG) aspect. • The upper range value of $\$50$/ton CO_2 is determined arbitrarily; however a more realistic upper limit in most jurisdictions for the coming years is probably more in the neighbourhood of $\$20$/ton CO_2.[1]			
Electricity mix	Coal Oil Natural gas Nuclear Hydroelectric Wind Solar Other (CO_2-free)	% (g CO_2/kWh)	CO_2-free mix – 100% coal (0 –1,071)	CO_2-free mix
Justifications	• Again, the base case electricity mix has no impact, since the base case does not consider any influence from the greenhouse gas (GHG) aspect. So it is assumed to be a CO_2-free mix. • The upper range value of 1,071 grams CO_2 /kWh corresponds to the GHG emissions associated with electricity produced 100% from coal.[2]			
f_e	Fuel economy of FCV with electrolytic hydrogen	km/ kg H_2 (gasoline equiv., L/100km)	-	135 (3.02)
Justifications	• Justifications for the base case fuel economy are given in table D.1 with the parameters used to determine the hydrogen demand of the station.			

…table continues next page.

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[1] CO_2e web site: www.co2e.com

[2] Dones R., Gantner U., Hirschberg S. "Greenhouse Gas Total Emissions from Current and Future Energy and Heat Supply Systems". In: Proceedings of the 4th International Conference on Greenhouse Gas Control Technologies, Interlaken, Switzerland, 31 Aug.- 2 Sept. 1998, Pergamon, Amsterdam, 1999. 891-896.

Parameter		Units	Range considered	Base case
Fuel economy of other fuelling options	FCV with hydrogen from decentralized SMR	gasoline equiv, L/100km	-	3.02
	Methanol FCV with on-board reforming		-	4.19
	Gasoline FCV with on-board reforming			6.11
	Gasoline ICE vehicle			7.30
Justifications	• All the base case values for the fuel economy and CO_2-equivalent emissions of other fuel options are based on values used in a report written by the Pembina Institute [1]. A Mercedes-Benz A-Class (5 seats) is used as the reference vehicle for each fuelling option, and the fuel economy is always calculated based on the U.S. Environmental Protection Agency (EPA) combined urban and highway driving cycle (45% highway and 55% city driving). The fuel economy values for an A-Class Mercedes-Benz FCV, running on compressed hydrogen, methanol or gasoline from an on-board fuel processing system, were obtained from Ballard Power Systems as their "probable case". The fuel economy of the gasoline ICE A-Class Mercedes-Benz was obtained from a Mercedes-Benz dealer, based on reformulated gasoline as the fuel.			
CO_2 equivalent emissions of other fuelling options	FCV with hydrogen from decentralized SMR	g CO_2 equiv./ km	-	86
	Methanol FCV with on-board reforming		-	162
	Gasoline FCV with on-board reforming		-	193
	Gasoline ICE vehicle		-	248
Justifications	• The base case GHG emissions associated with each fuel option are based again on the same report written by the Pembina Institute [1]. They include emissions from the whole energy chain, from extraction of the fuel to its processing, distribution and final use. The Pembina report explains clearly how emissions at the various steps were calculated for each fuelling option considered and which reference sources were used.			

Table D.4: Base case values and range for parameters used to calculate the "GHG Added Cost or Saving" of the fuelling station.

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[1] Pembina Institute for Appropriate Development, Climate-Friendly Hydrogen Fuel: A Comparison of the Life-cycle Greenhouse Gas Emissions for Selected Fuel Cell Vehicle Hydrogen Production Systems. Report written with support from The David Suzuki Foundation, March 2000, 44 p.

Appendix E – Site-Specific Information

In Chapter 4, the fuelling cost of using electrolytic hydrogen in a FCV was compared with the fuelling cost of the equivalent vehicle using gasoline in an ICE, for three different locations: Vancouver (Canada), Los Angeles (United States), and Paris (France).

The same base case electrolyser station, designed to serve 100 vehicles and assumed to have the exact same total installed capital cost, was placed in each location. The fuelling cost for the two fuel options in each city was calculated based on an equivalent driving range for the hydrogen FCV and gasoline ICE vehicle.

The data used for calculating the fuelling costs of the two options in each city is summarized in Chapter 4 in a table that is reproduced below. The sources used and calculations performed to obtain the site-specific information in that table are explained in this appendix.

Site-specific information	**Vancouver**	**Los Angeles**	**Paris**
* Electricity price (US¢/kWh)	3.2	12.8	5.9
Electricity mix	Dominated by hydroelectric (93%)	Dominated by NG (50%) and coal (11%)	Dominated by nuclear (82%)
† Tax on fuel (US$/GJ)	5.98	2.90	27.23

* Electricity prices calculated using local tariff schedule for an electrolyzer station supporting 100 hydrogen FCVs, with a capacity factor of 0.7.

† Hydrogen taxed at same rate as on gasoline, on an energy content basis (HHV).

CO_2 monetary valuation	• US$ 20/ton CO_2-equivalent
Vehicle range	• 600 km/full tank on EPA combined driving cycle (Identical for both the gasoline ICE vehicle and the hydrogen FCV)
Fuel economy	• Gasoline ICE vehicle: 7.30 liter /100 km • Hydrogen FCV: 3.02 liter /100 km (gasoline equivalent) corresponds to 135 km /kg H_2

Table E.1: Site-specific information to compare the price of electrolytic hydrogen and gasoline

Electricity Price

The electricity price in US¢/kWh was calculated as follows for each of the three locations, using the same number of daily hours of operation, year-round. The electricity tariffs were obtained directly from the utilities' web sites: respectively BC Hydro in Vancouver [1], Southern California Edison in Los Angeles [2], and Électricité de France in Paris [3].

- Amount of hydrogen required in each location: 14,222 kg H_2/year
  ⇒ 38.9 kg H_2/day

- Total energy requirements of station according to base case: 56 kWh /kg H_2

  56 kWh /kg H_2 × 14,222 kg H_2/year ≈ 796,000 kWh /year
  ⇒ 66,370 kWh /month
  ⇒ 2,182 kWh /day

- Power requirements for the station:

Base case capacity factor	$f = 0.7$
Base case peak-to-average-demand ratio	$R_{pd} = 1.2$
Average daily hours of operation:	0.7 × 24 hours/day = 16.8 hrs/day
Average power requirements:	2,182 kWh/day ÷ 16.8 hrs = 130 kW
Maximum power requirements:	1.2 × 130 kW = 156 kW

Electricity Price in Vancouver

- Electricity Tariff: "Medium Power Schedule 1200", with values from 2003
- Basic charge: CAN$ 4.15/month × 12 ≈ CAN$ 50 /yr
- Demand charge: First 35 kW of billing demand per month: Nil

  Next 115 kW of billing demand per month: $ 3.32/kW
  $ 3.32/kW × 115kW × 12 months ≈ CAN$ 4,582 /yr

  All additional kW of billing demand per month: $ 6.37/kW
  $ 6.37/kW × 6kW × 12 months ≈ CAN$ 459 /yr

  CAN$ 5,091 /yr

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[1] BC Hydro web site: www.bchydro.com
[2] Southern California Edison web site: www.sce.com
[3] Électricité de France web site: www.edf.fr

- Energy charge: First 14,800 kWh per month @ CAN$ 0.0649/kWh
  All additional kWh per month @ CAN$ 0.0312/kWh

[(14,800 × $ 0.0649/kWh) + (51,570 × $ 0.0312/kWh)] × 12 mths ≈ CAN$ 30,834 /yr

CAN$ 35,925 /yr

- Total annual electricity requirements of the station: 796,000 kWh
  CAN$ 35,925 /yr ÷ 796,000 kWh = CAN$ 0.0451 /kWh

- Currency exchange rate: CAN$ 1.00 = US$ 0.71
  CAN$ 0.0451 /kWh × 0.71 = US$ 0.0320 /kWh (excluding all taxes)

Electricity price in Vancouver: 3.2 ¢/kWh

Electricity Price in Los Angeles

- Electricity Tariff: "Schedule TOU-GS-2-SOP", with values from 2003
  (Time-of-use - general service - super off-peak - demand metered)

- Customer charge: US$ 79.25/ month × 12 months ≈ $ 951 /yr

- Demand charge: Facilities related:
  Per kW of billing demand per month: $ 5.40/kW
  $ 5.40/kW × 156kW × 12 months ≈ $ 10,109 /yr

  Time related:
  Per kW of billing demand per month:
  Summer (3 mth): $ 1.15/kW; Winter (9 mth): $ 0.55/kW

  [($ 1.15/kW × 3 months) + ($ 0.55/kW × 9 months)] × 156kW ≈ $ 1,310 /yr

  $ 12,370 /yr

- Energy charge: Super off-peak: 6 hours a day year-round @ $ 0.08566 /kWh
  Mid-peak hours during Summer @ $ 0.12621 /kWh
  Mid-peak hours during Winter @ $ 0.12698 /kWh

  6 hrs/day × 130 kW × $ 0.08566 /kWh × 365 days/yr ≈ $ 24,387 /yr
  10.8 hrs/day × 130 kW × $ 0.12621 /kWh × 91 days/yr ≈ $ 16,125 /yr
  10.8 hrs/day × 130 kW × $ 0.12698 /kWh ×274 days/yr ≈ $ 48,848 /yr

  $ 89,360 /yr

$101,730 /yr

- Total annual electricity requirements of the station: 796,000 kWh

  $ 101,730 /yr ÷ 796,000 kWh = $ 0.1278 /kWh (excluding all taxes)

Electricity price in Los Angeles: 12.8 ¢/kWh

Electricity Price in Paris

- Electricity Tariff: "Tarif Jaune Base", with values from 2003
- Demand charge: "Utilisations Longues"

  Per kW of billing demand per year: € 47.76/kW

  € 47.76/kW × 156kW ≈ € 7,450 /yr

- Energy charge: Off-peak hours: 8 hours a day year-round
  Off-peak hours during Winter (5 months) @ € 0.05491 /kWh
  Off-peak hours during Summer (7 months) @ € 0.02143 /kWh
  Other hours during Winter @ € 0.07728 /kWh
  Other hours during Summer @ € 0.02721 /kWh

  8 hrs/day × 130 kW × € 0.05491 /kWh × 151 days/yr ≈ € 8,623 /yr
  8 hrs/day × 130 kW × € 0.02143 /kWh × 214 days/yr ≈ € 4,769 /yr
  8.8 hrs/day × 130 kW × € 0.07728 /kWh × 151 days/yr ≈ € 13,350 /yr
  8.8 hrs/day × 130 kW × € 0.02721 /kWh × 214 days/yr ≈ € 6,661 /yr

  € 33,403 /yr

  € 40,853 /yr

- Total annual electricity requirements of the station: 796,000 kWh

  € 40,853 /yr ÷ 796,000 kWh = € 0.0513 /kWh

- Currency exchange rate: € 1.00 = US$ 1.15

  € 0.0513 /kWh × 1.15 = US$ 0.0590 /kWh (excluding all taxes)

Electricity price in Paris: 5.9 ¢/kWh

Electricity Mix

The electricity mix for Vancouver and Paris were obtained from the web site of their respective power utility: BC Hydro and Électricité de France. For Los Angeles, the electricity mix was obtained from a report of the California Energy Commission. [1]

Gasoline Price and Taxes

The gasoline price and taxes for each location were estimated based on data from a report of the International Energy Agency. [2]

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[1] Wetherall R. "2001 Net System Power Calculation (2001 California Power Mix)", California Energy Commission, April, 2002.

[2] International Energy Agency (IEA), World Energy Outlook, 1998 Edition, IEA/OECD, Paris, France, 1999.